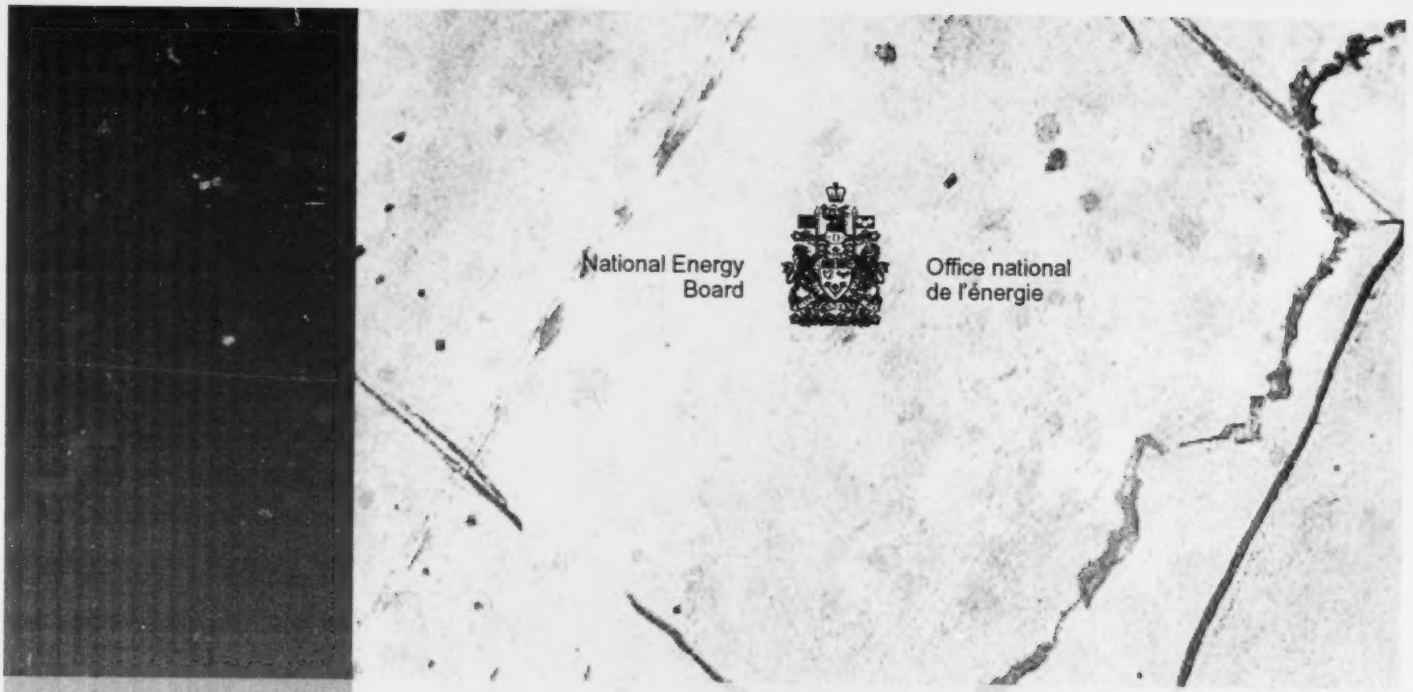
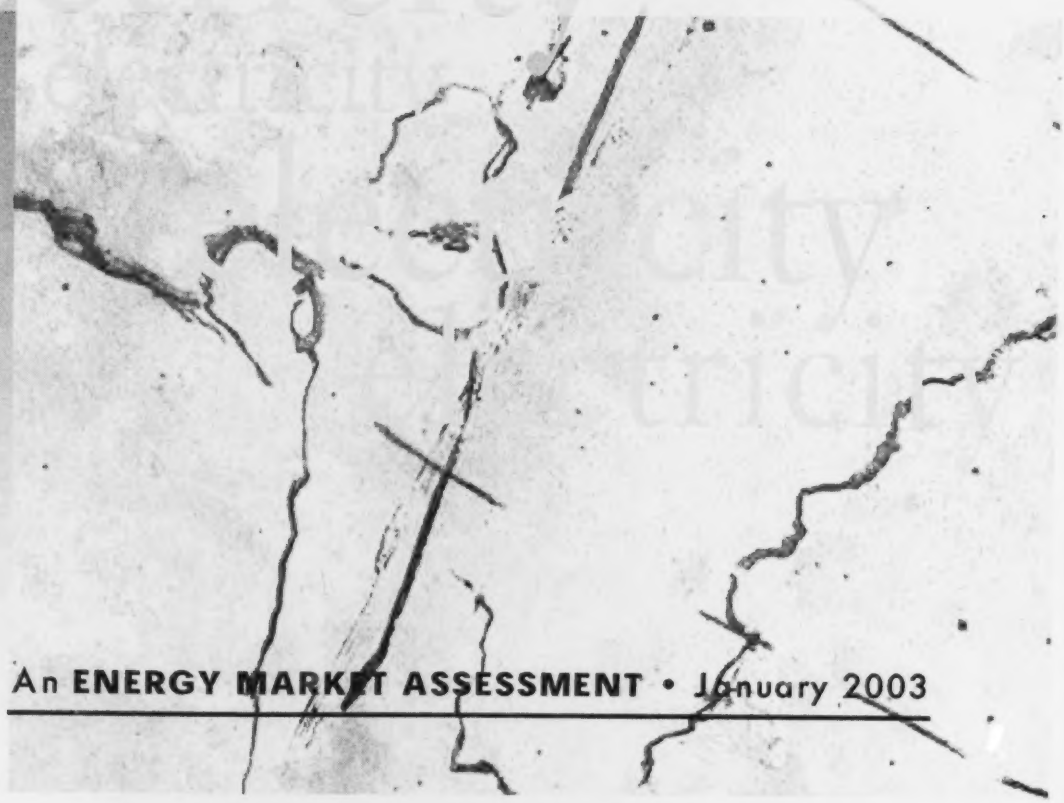
National Energy Board

Office national de l'énergie



Canadian **Electricity**

Exports *and* Imports



An **ENERGY MARKET ASSESSMENT** • January 2003

103-05186/

National Energy Board

Office national de l'énergie

Canadian **Electricity**

Exports *and* **I**mports

An **ENERGY MARKET ASSESSMENT** • January 2003

© Her Majesty the Queen in Right of Canada as represented by the National Energy Board 2003

Cat. No. NE23-106/2003E
ISBN 0-662-33417-5

This report is published separately in both official languages.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-Mail: publications@neb-one.gc.ca
Fax: (403) 292-5576
Phone: (403) 299-3562
1-800-899-1265
Internet: www.neb-one.gc.ca

For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

© Sa Majesté la Reine du chef du Canada représentée par l'Office national de l'énergie 2003

N° de cat. NE23-106/2003F
ISBN 0-662-88302-0

Ce rapport est publié séparément dans les deux langues officielles.

Exemplaires disponibles sur demande auprès du :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courrier électronique : publications@neb-one.gc.ca
Télécopieur : (403) 292-5576
Téléphone : (403) 299-3562
1-800-899-1265
Internet : www.neb-one.gc.ca

En personne, au bureau de l'Office :
Bibliothèque
Rez-de-chaussée

Imprimé au Canada

TABLE OF CONTENTS

Tables iii

Figures iii

Acronyms iv

Energy Units v

Foreword vi

Executive Summary vii

Chapter 1: Introduction 1
- 1.1 NEB's Role in Electricity Regulation 1
- 1.2 Electricity Industry Restructuring 2
  - 1.2.1 Restructuring Defined 3
  - 1.2.2 Status of Restructuring in Canada 3
  - 1.2.3 Restructuring in U.S. Electricity Markets 5

Chapter 2: Electricity Exports and Imports - National Perspectives 8
- 2.1 Transmission 8
- 2.2 Exports and Imports 10
- 2.3 Export and Import Prices 11

Chapter 3: Provincial Analyses of Electricity Exports and Imports 13
- 3.1 British Columbia 13
  - 3.1.1 Transmission Interconnections 13
  - 3.1.2 Exports and Imports 14
  - 3.1.3 Export and Import Prices 15
  - 3.1.4 Implications for Domestic Consumer Prices 16
  - 3.1.5 Factors Influencing Future Trade 17
- 3.2 Yukon Territory, Northwest Territories and Nunavut 17

3.3	Alberta		17
	3.3.1	Transmission Interconnections	18
	3.3.2	Exports and Imports	18
	3.3.3	Export and Import Prices	19
	3.3.4	Implications for Domestic Consumer Prices	21
	3.3.5	Factors Influencing Future Trade	22
3.4	Saskatchewan		23
	3.4.1	Transmission Interconnections	23
	3.4.2	Exports and Imports	23
	3.4.3	Export and Import Prices	24
	3.4.4	Implications for Domestic Consumer Prices	24
	3.4.5	Factors Influencing Future Trade	25
3.5	Manitoba		26
	3.5.1	Transmission Interconnections	26
	3.5.2	Exports and Imports	27
	3.5.3	Export and Import Prices	28
	3.5.4	Implications for Domestic Consumer Prices	29
	3.5.5	Factors Influencing Future Trade	29
3.6	Ontario		30
	3.6.1	Transmission Interconnections	30
	3.6.2	Exports and Imports	30
	3.6.3	Export and Import Prices	32
	3.6.4	Implications for Domestic Consumer Prices	33
	3.6.5	Factors Influencing Future Trade	34
3.7	Québec		34
	3.7.1	Transmission Interconnections	34
	3.7.2	Exports and Imports	35
	3.7.3	Export and Import Prices	36
	3.7.4	Implications for Domestic Consumer Prices	37
	3.7.5	Factors Influencing Future Trade	37
3.8	New Brunswick		38
	3.8.1	Transmission Interconnections	38
	3.8.2	Exports and Imports	39
	3.8.3	Export and Import Prices	40
	3.8.4	Implications for Domestic Consumer Prices	41
	3.8.5	Factors Influencing Future Trade	41
3.9	Prince Edward Island		42
3.10	Nova Scotia		42
3.11	Newfoundland and Labrador		42

Chapter 4: Observations 44

Glossary 48

TABLES

1.1	Status of Canadian Electricity Restructuring	4

FIGURES

1.1	Electricity Markets and Potential RTOs (map)	6
2.1	Canadian Electricity Exports as a Percentage of Generation 1997-2001 Average	9
2.2	Major Transmission Interconnections (map)	9
2.3	Canadian Electricity Exports and Imports (1990-2002)	10
2.4	Canadian Electricity Exports by Province (1990-2002)	11
2.5	Canadian Electricity Export and Import Prices (1990-2002)	12
2.6	Canadian Electricity Export Revenue and Import Costs (1990-2002)	12
3.1.1	British Columbia Exports and Imports (1990-2002)	14
3.1.2	British Columbia Export and Import Prices vs. Mid-C and COB (1996-2002)	15
3.1.3	British Columbia Export Revenue and Import Costs (1990-2002)	16
3.3.1	Alberta Exports and Imports (1990-2002)	19
3.3.2	Alberta Export and Import Prices vs. Mid-C (1996-2002)	20
3.3.3	Alberta Export Revenue and Import Costs (1990-2002)	20
3.3.4	Alberta Export and Import Prices vs. Power Pool of Alberta (1996-2002)	21
3.4.1	Saskatchewan Exports and Imports (1990-2002)	24
3.4.2	Saskatchewan Export and Import Prices vs. MAPP-North (1996-2002)	25
3.4.3	Saskatchewan Export Revenue and Import Costs (1990-2002)	25
3.5.1	Manitoba Exports and Imports (1990-2002)	27
3.5.2	Manitoba Export and Import Prices vs. MAPP-North (1996-2002)	28
3.5.3	Manitoba Export Revenue and Import Costs (1990-2002)	29
3.6.1	Ontario Exports and Imports (1990-2002)	31
3.6.2	Ontario Export and Import Prices vs. U.S. Northeast and IMO Prices (1996-2002)	32
3.6.3	Ontario Export Revenue and Import Costs (1990-2002)	33
3.7.1	Québec Exports and Imports (1990-2002)	35
3.7.2	Québec Export and Import Prices vs. U.S. Northeast Prices (1996-2002)	36
3.7.3	Québec Export Revenue and Import Costs (1990-2002)	37
3.8.1	New Brunswick Exports and Imports (1990-2002)	39
3.8.2	New Brunswick Export and Import Prices vs. U.S. Northeast Prices (1996-2002)	40
3.8.3	New Brunswick Export Revenue and Import Costs (1990-2002)	41

Acronyms

BC Hydro - British Columbia Hydro and Power Authority

BCUC - British Columbia Utilities Commission

BPA - Bonneville Power Administration

COB - California-Oregon Border trading hub

ECTO - East Coast Transmission Organization

ERCOT - Electric Reliability Council of Texas

EUB - Alberta Energy and Utilities Board

FERC - Federal Energy Regulatory Commission (U.S.)

GIC - Governor in Council

HVDC - High voltage direct current

IMO - Independent Electricity Market Operator of Ontario

IPPs - Independent Power Producers

MAPP - Mid-Continent Area Power Pool

Mid-C - Mid-Columbia trading hub in East-Central Washington

MISO - Midwest Independent Transmission System Operator, Inc.

NB Power - New Brunswick Power Corporation

NEB - National Energy Board

NEB Act - National Energy Board Act

NEPOOL - New England Power Pool

NERC - North American Electric Reliability Council

NPCC - Northeast Power Coordinating Council

NSPI - Nova Scotia Power Incorporated

OEB - Ontario Energy Board

OPG - Ontario Power Generation Inc.

PIRA - Petroleum Industry Research Associates

PJM - Pennsylvania/New Jersey/Maryland Interconnection

RTO - Regional Transmission Organization

SMD - Standard Market Design (FERC)

TVA - Tennessee Valley Authority

Energy Units

Prefixes		*Equivalent*
k	kilo	10^3
M	mega	10^6
G	giga	10^9
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Power Measures

kW	kilowatt	= 10^3 watts
MW	megawatt	= 10^6 watts
GW	gigawatt	= 10^9 watts
TW	terawatt	= 10^{12} watts

Energy Measures

		Energy Content
kW.h	kilowatt hour	3.6 MJ
MW.h	megawatt hour	3.6 GJ
GW.h	gigawatt hour	3.6 TJ
TW.h	terawatt hour	3.6 PJ

Note: A kilowatt hour is the amount of energy required to operate ten 100-watt light bulbs for an hour.

Metric to Imperial Units

1.0546 GJ	= 1 million British thermal units (Btu)

FOREWORD

This Energy Market Assessment (EMA) has been undertaken by the National Energy Board (NEB or the Board) as part of its regulatory mandate with respect to the monitoring of Canadian energy markets. The NEB's first electricity EMA, entitled *Canadian Electricity Trends and Issues*, was published in May 2001. That report provided an overview of restructuring of the electricity industry and examined the electricity markets across Canada on a provincial basis, including demand and generation; international and interprovincial trade; regulatory developments (including restructuring initiatives) and electricity prices.

This report focuses on recent trends in Canadian electricity exports and imports, and the associated revenue and pricing, in the context of the major developments in electricity markets in Canada and the United States over the past decade. This includes discussion of some of the issues and implications of electricity trade for consumers and the electricity industry. "Exports" and "imports" refer to international transfers of electricity, recognizing that from a provincial standpoint, exports and imports may also include interprovincial transfers.

The timing of this EMA is guided by the recent increase in applications to the NEB for electricity exports and international power lines. In addition, there have been significant market developments such as the opening of electricity markets in Alberta and Ontario and the evolution of Regional Transmission Organizations in the U.S., which may affect the outlook for Canadian electricity trade. The report is intended to contribute to the public's understanding and awareness of current developments in the Canadian electricity sector, and is the first in an annual series of EMAs examining electricity exports and imports and related matters.

Chapter 1 starts with an overview of the current Canadian federal regulatory regime under which exports take place before moving on to a brief update on electricity restructuring in Canada and the U.S. Chapter 2 presents an overview of electricity exports and imports from a national perspective. Chapter 3 provides an analysis by province, covering international interconnections, export and import trends, export and import prices, implications for domestic consumer prices and factors influencing future trade. Chapter 4 concludes with a number of observations.

The analysis is based primarily on data submitted to the NEB by electricity exporters and augmented by information obtained through consultations with interested parties representing exporters, electricity generators, power consumers and public interest groups. The Board appreciates the information and comments it received.

Executive Summary

This Energy Market Assessment has been undertaken by the National Energy Board (NEB or the Board) as part of its regulatory mandate with respect to the monitoring of Canadian energy markets. The report focuses on recent trends in Canadian electricity exports and imports, and the associated revenue and pricing, in the context of the major developments in electricity markets in Canada and the United States (U.S.) over the past decade. This includes discussion of some of the issues and implications of electricity trade for consumers and the electricity industry.

Exports and imports in this report refer to international electricity transfers between Canada and the U.S.

Electricity Exports and Imports

Canada has historically been an exporter of electricity to the U.S. While there is substantial variation among the provinces, at the national level electricity exports have typically been 7-9 percent of generation. Québec, Manitoba and British Columbia (B.C.), where hydro power is the dominant source of electricity generation, have accounted for 80-85 percent of Canadian exports in recent years.

Exports increased in the early 1990s, largely resulting from surplus generating capacity in Manitoba, Ontario and Québec. The restructuring of electricity markets, particularly in regard to the emergence of independent power producers and improved access to transmission systems, has resulted in increased opportunities for trade, but has not resulted in increased exports. On balance, exports have declined over the past five years reflecting increased domestic demand combined with no corresponding increase in generation capacity.

Since 1996 electricity imports have increased, partly due to higher imports to Ontario following the lay-up (removal from service) of a number of nuclear generating units. In addition, importers, mainly in B.C. and Québec, have taken advantage of energy trading opportunities as access to U.S. transmission systems improved, following the implementation of Order 888 by the U.S. Federal Energy Regulatory Commission (FERC).

As a result of lower exports and higher imports, net exports declined from 40 terawatt hours (TW.h) in 1996 to an estimated 25 TW.h in 2002. However, because of higher electricity export prices, Canadian international trade in electricity has continued to yield net revenues of $1 billion to $2 billion per year, except in 2000 and 2001, when they were about $3 billion.

The magnitude of trade and factors motivating trade vary by province. Manitoba, Québec and B.C. are direct exporters from their generation reserve margins, whereas the provinces of Ontario, Saskatchewan and Alberta, which mainly rely on thermal generation, utilize exports and imports to optimize the use of generating facilities and provide system reliability. Apart from these

considerations, thermal generation technology is not much different in Canada than it is in the U.S., and there is not much difference in the availability and price of fuels. Therefore, gas-fired or coal-fired generation in Canada and adjacent regions in the U.S. tend to have similar costs.

Although the NEB has seen some acceleration in interest for new export permits, recent export trends do not lend support to the prospect of a substantial increase in electricity exports in the immediate future. There is some potential upside to exports that could result from the return to service of nuclear units in Ontario, depending on the timing, and continued availability of Ontario's other supply options.

Over the longer term, electricity exports may increase due to: the possibility of large hydro developments; the capacity surplus that may result from cogeneration projects associated with oil sands development in Alberta; and improved transmission access to U.S. markets. Imports may also increase over time as a result of increased trading activities, particularly from provinces with hydro storage capacity.

Electricity Export and Import Prices

Electricity markets are regional in nature. Thus, provincial export and import prices often reflect the pricing trends in adjacent U.S. wholesale markets. This suggests that there is some degree of market integration at the wholesale level, i.e., power can flow based on market price signals and the provinces can benefit from being able to export or import. In some cases, market integration is constrained by existing transfer limits on transmission systems and/or transmission congestion, and not all provinces have direct access to the export market (e.g., Alberta, Nova Scotia and Newfoundland and Labrador).

The relationship between export and import prices varies from province to province. When export prices are higher, particularly for the hydro provinces, it is because exports generally occur during peak periods when prices are relatively high and imports occur during off-peak periods. When import prices are higher than export prices, it is normally because imports are needed at peak periods, to compensate for local supply deficiencies.

Implications for Consumers

In recent years, electricity prices have been extremely volatile in some market areas, as evidenced by trends in import and export prices. Volatility can be exacerbated by fundamental supply/demand imbalances, for example, when growth in generation fails to match growth in demand.

Canadian consumers remain generally protected from price volatility through utility regulation. Moreover, some provinces, such as B.C., Manitoba, Québec and New Brunswick, use export revenue to maintain domestic electricity prices at levels that are lower than they would otherwise be. Since May 2002, Ontario has had a competitive wholesale market in the form of the IMO-administered market. However, with the implementation of a retail price cap until 2006, a large portion of Ontario electricity consumers will not be affected by price changes in the wholesale market. Thus, with the exception of Alberta, there is no direct relationship between the prices most Canadian consumers pay and competitive wholesale prices. From this perspective, domestic electricity prices are different from oil and gas prices, which reflect supply and demand conditions in competitive markets.

Transmission and Regional Transmission Organizations (RTOs)

The structure of the North American transmission grid is being reshaped by the FERC RTO and Standard Market Design (SMD) initiatives. Many market participants believe that RTO development will promote trade by increasing access and lowering transmission costs.

Practically all provinces have expressed interest in some form of participation in RTOs. Manitoba has already concluded a coordination agreement with the Midwest Independent System Operator and B.C., New Brunswick and Nova Scotia have supported RTO membership. Québec, Ontario and Alberta are assessing their strategic options. Apart from the technical challenges posed by the implementation of SMD, or achieving operational compatibility with SMD, concerns in Canada have been raised with respect to regulatory sovereignty, RTO governance, and ensuring that the interests of Canadian consumers are not compromised.

Canadian entities have also identified the need for more transmission to the U.S. as a means to foster future trade. To improve access to U.S. markets, a number of new transmission projects have been proposed over the past two to three years. An innovative aspect of some of these proposals is that they would be merchant power lines, targeting specific export markets.

INTRODUCTION

This report examines trends in electricity exports and imports, and the associated revenue and pricing, in the context of the major developments in Canadian and U.S. electricity markets over the past decade, and discusses some of the issues and implications of this trade for consumers and the electric industry.[1]

In this chapter the Canadian federal regulatory regime under which exports take place is described (imports are not regulated by the NEB). In addition, because electricity trade will likely be affected by the restructuring of North American electricity markets, an update of the status of restructuring is provided.

1.1 NEB's Role in Electricity Regulation

The responsibilities of the National Energy Board (NEB or the Board) with respect to the electricity industry pertain to the construction, operation and abandonment of international power lines and designated interprovincial power lines, and electricity exports.[2] Companies seeking to either export electricity or to construct and operate an international power line (IPL) must first obtain NEB approval. The NEB's responsibilities are defined in the *National Energy Board Act* (NEB Act), a federal act of parliament initially promulgated in 1959. Significant amendments were made to the NEB Act to implement the *Canadian Electricity Policy* (1988). The Board also has responsibilities under the *Canadian Environmental Assessment Act* (1995).

With the exception noted below, the NEB Act (section 119.03) states that "the Board shall on application to it and without holding a public hearing issue a permit authorizing the exportation of electricity." The responsibilities of the applicant and information to be provided to the Board in obtaining approval to export electricity are referenced in the NEB Act (section 119.02(2)) and specifically described in the Board's Electricity Regulations[3] and Memorandum of Guidance.[4]

In practice, most of the Board's electricity export authorizations result in the issuance of a permit. However, if, after consideration of the relevant factors, the Board believes that the project warrants

1 Unless otherwise specified, exports and imports in this report refer only to international electricity transfers between Canada and the United States (U.S.). It is common practice in some provinces to refer to interprovincial deliveries as exports (in addition to international deliveries) and to refer to interprovincial receipts as imports (in addition to international receipts).

2 No interprovincial power line has ever been designated for a certificate pursuant to section 58.4 of the *National Energy Board Act*.

3 *National Energy Board Electricity Regulations, SOR/97-130.*

4 *Memorandum of Guidance to Interested Parties Concerning Full Implementation of the September1988 Canadian Electricity Policy, Revised 26 August 1998.*

more detailed regulatory assessment, the Board may recommend to the Governor in Council (GIC)[1] that the application be designated for a public hearing, and deal with the application as an application for an export licence. The NEB Act (section 119.06(1)) states that:

> "in determining whether to make a recommendation, the Board shall seek to avoid the duplication of measures taken in respect of the exportation by the applicant and the government of the province from which the electricity is exported, and shall have regard to all considerations that appear to it to be relevant, including:
>
> (a) the effect of the exportation of the electricity on provinces other than that from which the electricity is exported;
>
> (b) the impact of the exportation on the environment;
>
> (c) whether the applicant has:
>
> (i) informed those who have declared an interest in buying electricity for consumption in Canada of the quantities and classes of service available for sale, and
>
> (ii) given an opportunity to purchase electricity on terms and conditions as favourable as the terms and conditions specified in the application to those who, within a reasonable time after being informed, demonstrate an intention to buy electricity for consumption in Canada; and
>
> (d) such considerations as may be specified in the regulations."

The considerations in (c) are referred to as providing Fair Market Access.

After a hearing, if the Board is satisfied that the export is in the public interest, the Board may issue an export licence, subject to GIC approval and to terms and conditions that the Board may impose. A denial of the application is not referred to the GIC. The Board has not held a public hearing on electricity exports since the NEB Act was revised in 1990 (to implement the Canadian Electricity Policy).

1.2 Electricity Industry Restructuring

In the traditional market structure of the electricity industry, generation, transmission and distribution of electricity are owned and managed by vertically-integrated monopolies. This form of market structure, which still prevails in much of Canada today, was widely adopted because the electricity supply industry was regarded as a natural monopoly. With respect to generation, this meant that lowest costs could be achieved by building large-scale centralized power plants. The nature of long-distance transmission systems and local distribution systems also fit the natural monopoly model. Even if competition were possible in generation, it would still not be economically feasible to build competing transmission and distribution facilities to serve the same market, i.e., lowest costs would be achieved by one facility. Because of the concern that monopolies would be able to exercise market power, most provincial governments made the operations of monopolies subject to the oversight of regulatory bodies.

In most Canadian provinces, public ownership was established in the form of Crown corporations. The utilities in each province tended to develop their own generation, transmission and distribution systems consistent with provincial energy requirements.

1 This is a subcommittee of the Prime Minister's cabinet.

In Canada and the U.S., a number of trends began to emerge in the late 1980s and early 1990s that caused several jurisdictions to question the traditional market structure:

(i) Technological advances in generation made the construction of smaller gas-fired generating units feasible, particularly combined-cycle natural gas turbines. These units can provide incremental supply at lower capital costs, and can be built more quickly than conventional fossil fuel or nuclear plants. At the same time, it became profitable for industrial electricity consumers to purchase natural gas to simultaneously produce process heat and electricity (cogeneration) and to sell any surplus electricity into the electricity grid.

(ii) Many jurisdictions, for example in the U.S. Northeast and California, took the view that access to a utility's transmission lines should be made available to other service providers to enable access to cheaper supplies from neighbouring regions, and regions further afield. An underpinning principle here is that access to transmission lines should be nondiscriminatory.

(iii) Experience with deregulation and restructuring in other industries such as telecommunications, natural gas and the airlines suggested that competition between producers and service providers would lower costs and provide a broader selection of services to consumers.

1.2.1 Restructuring Defined

Restructuring refers to reorganizing electric utilities from vertically-integrated monopolies into separate generation, transmission and distribution service companies. This separation, or unbundling, is intended to promote competition between generators, and to "open" the transmission and distribution systems, eventually increasing competition in the supply and marketing of electricity.

Restructuring may include both wholesale access and retail access. Wholesale access refers to generators having the ability to obtain access to transmission systems to compete in wholesale markets, which may include distribution companies or independent marketers. Retail access refers to marketers having the ability to obtain access to distribution systems to sell to end-use consumers, and conversely, allowing end-use consumers a choice among marketers. Full retail access occurs when all end-use consumers have this choice. Wholesale access can occur without retail access; however, retail access requires wholesale access.

1.2.2 Status of Restructuring in Canada

In Canada, the adoption of initiatives to restructure the electricity industry has varied across the country, as each province assesses its own unique regional circumstances and issues. Alberta restructured its electricity market over a five-year period culminating in full retail access on 1 January 2001. Ontario implemented full retail access on 1 May 2002. However, on 11 November 2002, due to supply uncertainties in the Ontario power market and volatility in consumer rates, the Ontario government imposed a price cap on the energy component of consumer bills and began an inquiry into other aspects of the operation of the market (refer to section 3.6).

As shown in Table 1.1, most other provinces, including British Columbia (B.C.), Saskatchewan, Manitoba, Québec, New Brunswick and Nova Scotia, have implemented, or are planning to implement, wholesale access.

TABLE 1.1

Status of Canadian Electricity Restructuring

	Wholesale Access	Retail Access	Comment
British Columbia	yes	large industrial consumers	- BC Hydro retail prices are frozen until 31 March 2003 - future prices will be regulated by the British Columbia Utilities Commission based on approved costs.
Yukon Territory, Northwest Territories & Nunavut	no	no	- prices are regulated by public utility boards - small, dispersed markets - no transmission interconnections with the provinces
Alberta	yes	yes	- wholesale prices are established in the market managed by the Power Pool of Alberta; pass-through to consumers who have various purchase options
Saskatchewan	yes	Cities of Saskatoon and Swift Current	- retail prices are subject to government approval
Manitoba	yes	no	-retail prices are approved by the Manitoba Public Utilities Board - coordination agreement with the Midwest Independent System Operator (September 2001)
Ontario	yes	yes	- wholesale prices are established in the IMO-administered market - pass-through to residential and other low-volume consumers is capped at 4.3 cents per kW.h until 2006
Québec	yes	large industrial consumers	- retail prices are regulated by the Régie de l'énergie du Québec - rates are frozen until 2004
New Brunswick	yes	large industrial consumers, planned for 2003	- retail prices are regulated by the Board of Commissioners of Public Utilities - the Province is implementing restructuring pursuant to its White Paper on Energy Policy
Prince Edward Island	no	no	- P.E.I. imports most of its electricity from New Brunswick - retail prices cannot exceed 110 percent of that paid for comparable service in New Brunswick (under the Maritime Electric Company Act)
Nova Scotia	market structure being developed	market structure being developed	- retail prices are regulated by the Nova Scotia Utility and Review Board - a "staged" approach to restructuring
Newfoundland and Labrador	no	no	- retail prices are regulated by the Board of Commissioner of Public Utilities - study of restructuring has been undertaken

On 25 November 2002, the B.C. Government released its new energy policy, which contains a number of actions directed toward the electricity industry.[1] One of these actions is that BC Hydro Transmission Corporation, a separate entity, will operate BC Hydro's transmission system with the purpose of ensuring fair access for all generators. This will allow independent power producers (IPPs) to serve large customers in B.C. and enable them to participate in U.S. wholesale markets (refer to section 3.1).

New Brunswick and Nova Scotia plan to introduce wholesale access over the next few years and limited retail access. Newfoundland has undertaken a study of restructuring, but has not announced the extent of any forthcoming changes. Aside from Ontario and Alberta, no other provinces are currently planning to implement full retail access.

1.2.3 Restructuring in U.S. Electricity Markets

The major current initiative in the restructuring of U.S. electricity markets is the formation of Regional Transmission Organizations (RTOs), as mandated by the U.S. Federal Energy Regulatory Commission (FERC). The purpose of RTOs is to facilitate non-discriminatory access to transmission systems and thereby promote competition in wholesale markets as intended by FERC Order 888.[2] A key aspect of Order 888 is the reciprocity requirement, which is particularly important for Canadian exporters. Reciprocity effectively requires that Canadian transmission companies provide U.S. marketers access to their transmission facilities; this enables Canadian exporters utilizing those facilities to obtain a licence from FERC to market electricity in U.S. wholesale markets.

FERC Order 2000 (December 1999) defined the functions and characteristics of an RTO.[3] In essence, an RTO would be composed of one or more transmission companies that would function as a single transmission entity. This structure is intended to promote competition in wholesale markets and reduce the cost of transmission within the RTO area by providing non-discriminatory access to transmission and eliminating rate pancaking. Importantly, benefits are also expected to result from the ability to more effectively plan for additions to transmission capacity and address the reliability issues in the restructured electricity market.[4] Given the international nature of transmission systems, Canadian participation in RTOs was invited.

In July 2001, the FERC in a series of orders proposed the creation of four RTOs in the U.S., one each in the Northeast, the Southeast, the Midwest, and West. ERCOT would be a fifth RTO.[5] After consultation, and to address issues raised by the industry and state regulators the FERC issued a

1 *Energy for Our Future: A Plan for BC*, November 2002.

2 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888*, April 1996, U.S. Federal Energy Regulatory Commission.

3 *Regional Transmission Organizations, Order No. 2000*, December 1999, U.S. Federal Energy Regulatory Commission.

4 It is often stated that the biggest uncertainty surrounding the future of electricity markets in the U.S. is the availability of transmission. Construction of transmission has lagged growth in electricity demand and is projected to do so in the foreseeable future. This is primarily due to the expected relatively low returns on transmission investments as compared to the relatively high risks (e.g., siting, environmental concerns, stranded investments).

It is also often stated that the current transmission system is being used for purposes it was not initially intended. That is, in the traditional utility model, markets tended to be more regional in scope and were joined at the "seams" for reliability purposes. With restructuring, there is now more requirement for bulk power transfers between regions causing pressure at the seams, and leading to congestion and reliability concerns. This is in addition to the tendency in competitive markets to reduce reserve margins.

5 ERCOT (The Electric Reliability Council of Texas) is one of the administrative regions of the North American Electric Reliability Council (NERC).

Notice of Proposed Rulemaking on Standard Market Design (SMD) in July 2002.[1] The main elements include a standard tariff, method of congestion management, market monitoring and ongoing input from state regulators by Regional State Advisory Councils. While the SMD final rule is expected to further the RTO initiative there remain several regional issues to be addressed. During the fall and winter of 2002/2003 the FERC has been engaging the industry and regulators, including Canadian interests, toward developing a final rule in 2003.

FERC's timetable is for implementation of SMD across the U.S. by the end of 2004. The exact timing and regional adaptation of SMD is expected to vary and the number of RTOs that will eventually result is uncertain. Potential RTOs and market areas are shown in Figure 1.1.

FIGURE 1.1

Electricity Markets and Potential RTOs

Source: NEB, FERC

1 *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 31 July 2002, U.S. Federal Energy Regulatory Commission.

Canadian Participation in RTOs

The terms of participation in RTOs for Canadian parties will be based on the unique circumstances and needs expressed by the transmission entities in each province. While some proposals are more advanced than others, some potential alignments are:

- Alberta and B.C. with RTO West (B.C. participated in the RTO West filing to the FERC)
- Saskatchewan and Manitoba with the Midwest Independent System Operator (MISO) (Manitoba has a coordination agreement with the MISO)
- Ontario with a northeastern RTO and/or the MISO
- Québec and the Atlantic Provinces with a northeastern RTO or ECTO (East Coast Transmission Organization).

The status of these potential alignments is addressed in the respective province in Chapter 3.

C H A P T E R T W O

Electricity Exports and Imports - National Perspectives

As indicated in Chapter 1, the electricity industry in Canada evolved along provincial lines, so generation and transmission systems were sized to meet provincial demand. However, surpluses became available for sale, either to another province or the U.S. These surpluses were caused by: the need to build for current peak demand (e.g., winter peak load), resulting in seasonal surpluses; the need to build for future domestic demand, resulting in a surplus between installed capacity and current domestic consumption; and the need to maintain reserve margins to handle contingencies, such as power plant outages and, in the case of hydro systems, low-water years. The interconnections between utilities in adjacent systems have been used to move surpluses, as well as to provide reliability.

Thus the factors driving the expansion of electricity production in Canada have been somewhat different from other energy commodities, such as oil and gas, for which development was to a large extent based on growth in export markets. In addition, there were concerns about publicly owned electric utilities taking the risk of building for an export market, which might not materialize or might be lost to competition from other electricity supplies, thus leaving the utility rate payers to bear the costs of stranded investments.

The quantity of electricity exported from Canada has typically been 7-9 percent of production in recent years, much less than the respective export shares of production for natural gas and oil. In 2001, gas exports accounted for 58 percent of production and oil exports were 62 percent.[1] However, the electricity export shares have varied substantially by province, with New Brunswick and Manitoba in the 20 to 30 percent range and Alberta less than one percent. Net export shares (exports minus imports) are somewhat lower (Figure 2.1).

2.1 Transmission

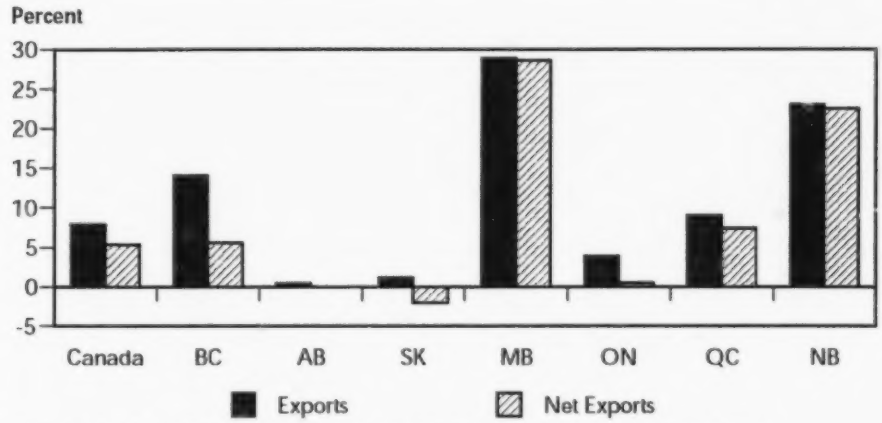
Most international trade in electricity is carried out directly across interconnections between provinces and the U.S., such as the large interconnections between British Columbia, Manitoba, Ontario, Québec and New Brunswick and their respective adjacent states (Figure 2.2).

Export trade also occurs by interprovincial transfers over the wires of an intermediate province. For example, Alberta has no direct ties to the U.S., but can access the U.S. through B.C. and to a lesser extent via its intertie with Saskatchewan. Québec has direct ties to the U.S., but when transmission capacity is available, it can also export electricity through New Brunswick and Ontario. Nova Scotia started exporting in 2001 via its intertie with New Brunswick. It is expected that open access will promote more of these indirect exports.

1 Canada's net exports of oil were 19 percent of production in 2001. Transportation logistics and refinery requirements favour importing oil to eastern Canada, while western Canadian production, which could otherwise be used instead of imports, is exported to the U.S.

FIGURE 2.1

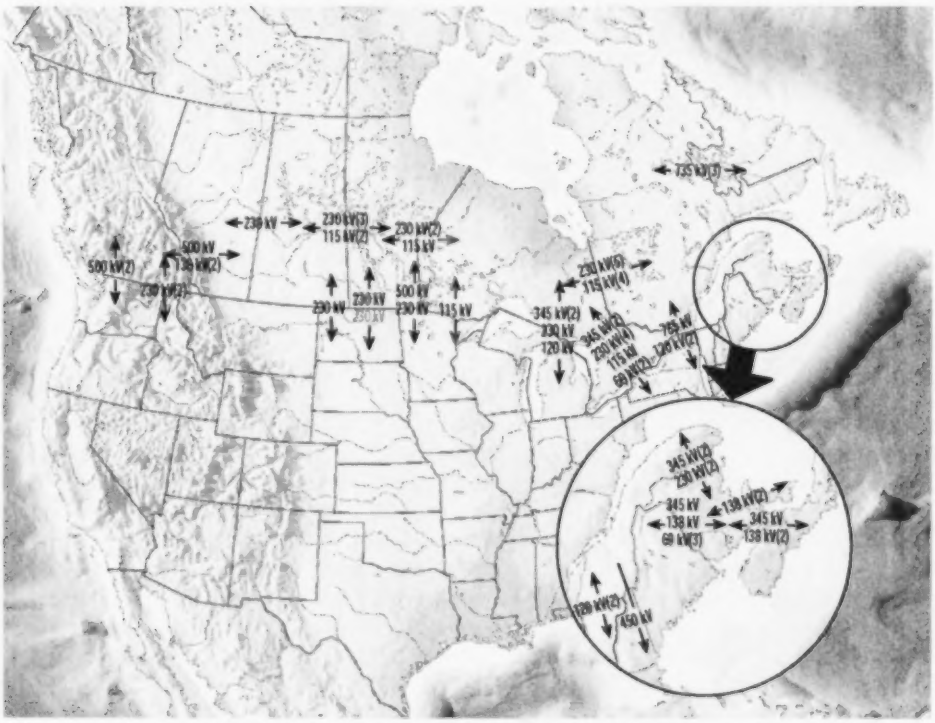
Canadian Electricity Exports as a Percentage of Generation 1997-2001 Average*



* Nova Scotia, P.E.I., Newfoundland & Labrador and the Territories had negligible or no exports or imports.
Source: NEB

FIGURE 2.2

Major Transmission Interconnnections



Note: The numbers indicate the voltage of the power lines from each province to adjoining provinces and the states. If there is more than one line with a given voltage, the number of lines is indicated in parentheses.
Source: NEB, Canadian Electricity Association and Natural Resources Canada.

2.2 Exports and Imports

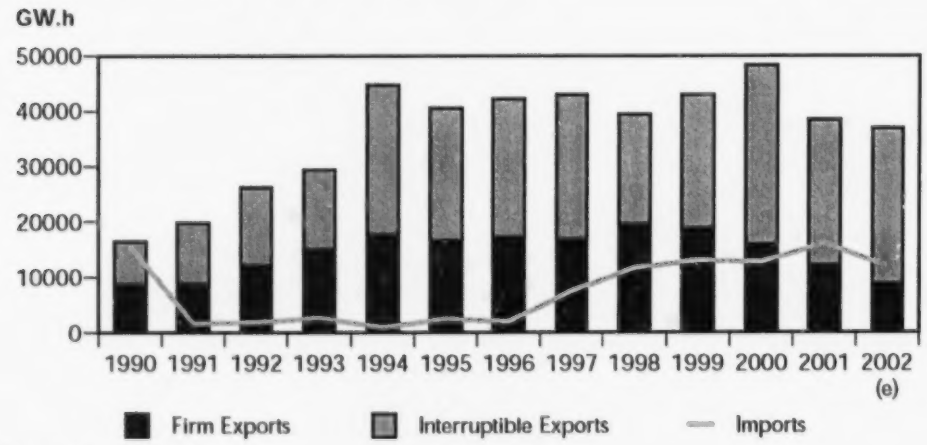
Exports

After a substantial increase in the early 1990s, largely resulting from the use of spare capacity in Manitoba, Ontario and Québec, Canadian electricity exports have typically been in the range of 35 to 45 TW.h per year (Figure 2.3). Because most exports originate from the hydro-rich provinces, a good deal of the annual variation can be accounted for by the annual variation in hydraulic conditions. On balance, exports have declined over the past four to five years reflecting increased domestic demand combined with no corresponding increase in generation capacity. Québec, Manitoba and B.C. dominate electricity exports, accounting for 80-85 percent of Canadian exports over the past five years (Figure 2.4).

With the restructuring of the electricity industry over the past several years, the terms under which exports occur have been changing from long-term deals towards more spot-related, short-term deals. In addition, many new players are engaging in trade, primarily independent marketers who are not affiliated with the "traditional" electric utilities. While the number of these entities holding export permits has increased, from one in 1993 to about 40 in 2002, they account for less than one percent of exports and export revenue. Reasons for the limited amount of export activity by independent marketers are apparently related to: (i) market constraints, such as the availability of transmission; (ii) arbitrage opportunities between the domestic and export markets being less than anticipated and (iii) unbundled traditional utilities retaining market share of export markets by creating successful marketing subsidiaries. Sales under firm arrangements have tended to decline as the arrangements under which electricity sales occur are governed more by short-term considerations. This is particularly evident in Québec (section 3.7) where firm contracts are expiring and are being replaced with interruptible contracts.

FIGURE 2.3

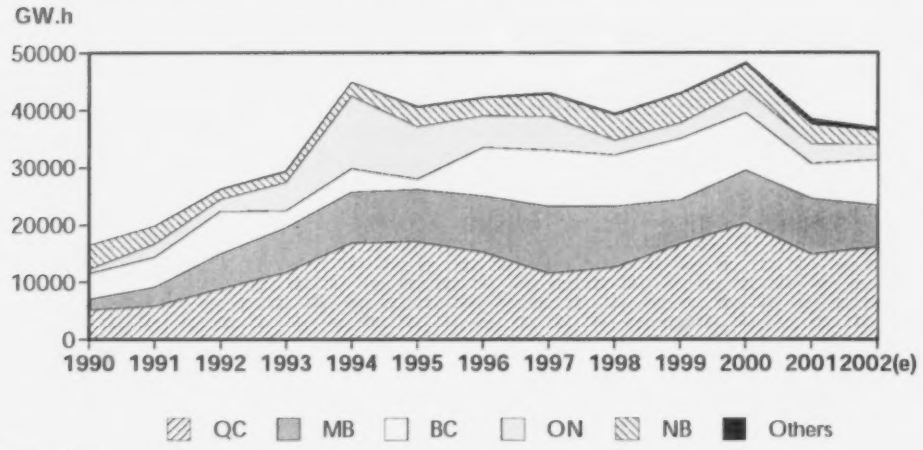
Canadian Electricity Exports and Imports



Source: NEB

FIGURE 2.4

Canadian Electricity Exports by Province



Source: NEB

Imports

Electricity imports in recent years have been in the range of 10 to 15 TW.h, with an upward trend (Figure 2.3). The increase after 1996 was partly due to increased imports to Ontario following the lay-up (removal from service) of a number of nuclear generating units.[1] In addition, importers in hydro-rich regions, mainly B.C. and Québec, took advantage of energy banking opportunities to increase trading revenues after transmission access was improved in both Canada and the U.S. with the implementation of FERC Order 888.[2]

The combination of a decline in exports and increasing imports has resulted in an overall decline in net exports from 40 TW.h in 1996 to an estimated 25 TW.h in 2002.

2.3 Export and Import Prices[3]

During the 1990s, annual export prices varied in a range of $30-$40 per MW.h (Figure 2.5) reflecting trends in U.S. bulk power markets. The pronounced uplift in 2000 and 2001 includes the impact on B.C. exports of the California electricity crisis. However, price increases in other U.S. power markets were also occurring, to some extent as the result of the effect of higher natural gas prices on gas-fired generation. Until 1997 import prices tended to be higher than export prices, largely reflecting the need to import electricity during peak periods, although that pattern varied across the country. Subsequently, export prices rose above import prices, with increasing price pressure from U.S. markets. Export and import prices during the 1990s were somewhat higher than they would have otherwise been, due to the decline of the Canadian dollar versus the U.S. dollar.[4]

1 The decline in imports in 1991 was mainly the result of nuclear units in Ontario coming back into service.

2 Energy banking refers to the storage of water in a reservoir during off-peak times to be released for generation during peak times when prices are higher.

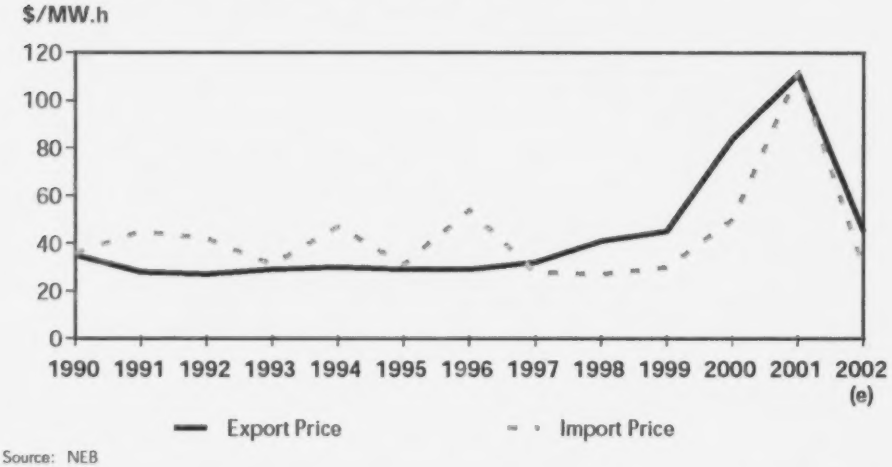
3 The prices for exports (imports) in this report reflect the average amount paid per MW.h of electricity exported (imported), based on the quantities and corresponding dollar amounts reported to the NEB.

4 The Canadian dollar declined by 23 percent during the 1991-1999 period, so export contracts that were settled in U.S. dollars would have increased in value in Canadian dollars.

Over the past decade electricity trade has made a positive contribution to Canada's balance of trade. Since 1994, net export revenue (exports less imports) has typically been in the range of $1 billion to $2 billion per year, with the exception of 2000 and 2001 when annual net revenue was about $3 billion (Figure 2.6).

FIGURE 2.5

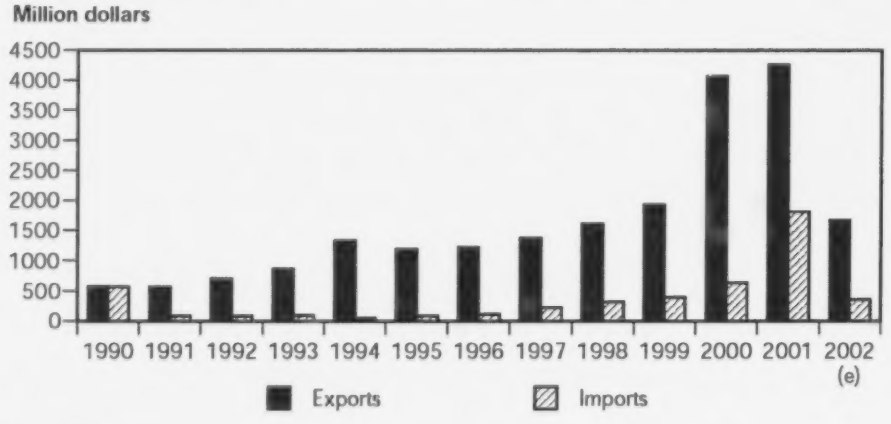
Canadian Electricity Export and Import Prices



Source: NEB

FIGURE 2.6

Canadian Electricity Export Revenue and Import Costs



Source: NEB

PROVINCIAL ANALYSES OF ELECTRICITY EXPORTS AND IMPORTS

3.1 British Columbia

British Columbia generates power predominantly from hydro-based resources. Thus, water levels, as determined by climatic conditions and alternative uses, such as irrigation, maintenance of fish habitat and recreational uses, are a key factor in influencing generation and the availability of power for export. Hydro generation provides the province with the ability to engage in "energy banking," i.e., storing water in reservoirs during off-peak periods for generation and export during peak periods (either daily or seasonal) when prices are higher. Depending on specific trading arrangements, low-priced power can be imported in off-peak periods. There is also the opportunity to utilize energy banking to engage in trade with Alberta. Since 1996, a significant factor supporting increased trade has been the "opening" of transmission systems in B.C. and adjacent markets in the U.S. Pacific Northwest, California and Alberta following the reciprocity provisions of FERC Order 888 (see Chapter 1).

In addition to domestic generation, B.C. also has access to other supplies to meet B.C. electricity requirements and to obtain energy for export; these include imports from the U.S. and Alberta plus the "return" of downstream benefits from the Columbia River Treaty.[1]

3.1.1 Transmission Interconnections

International trade is carried out mainly over two transmission corridors (Figure 2.2), one extending south from the Lower Mainland area consisting of two 500 kV power lines and another in the eastern part of the province connecting with the Mid-Columbia area in the State of Washington consisting of two 230 kV lines. Interconnections with Alberta allow interprovincial transfers of electricity and serve as an indirect link for Alberta to the U.S. market. These include two power lines at 138 kV and one at 500 kV.

1 The Treaty has been in effect since 1968. Dams built in B.C. enabled flood control and incremental electricity to be generated on the Columbia river on the U.S. side of the border. According to the Treaty, half the increase in electricity generation at those facilities belongs to B.C. For the first 30 years of the agreement the Canadian rights to the power were sold to the U.S. In 1998, B.C. started taking its share of the downstream benefits in the form of electricity, which it could use either to meet demand in B.C. or sell in U.S. markets. Powerex, a subsidiary of BC Hydro which deals with export and trading activities, markets this electricity on behalf of the B.C. government.

3.1.2 Exports and Imports[1]

Exports

Exports have varied between 2 000 and 11 000 GW.h per year over the past 10 years (Figure 3.1.1). Exports tend to be highest when conditions are favourable in B.C. and electricity demand is strong in U.S. markets, particularly in the States of Washington, Oregon and California. Based on data for 2001, the main exporter was Powerex. Smaller quantities were reported by Cominco, Dynegy, Aquila and other companies.

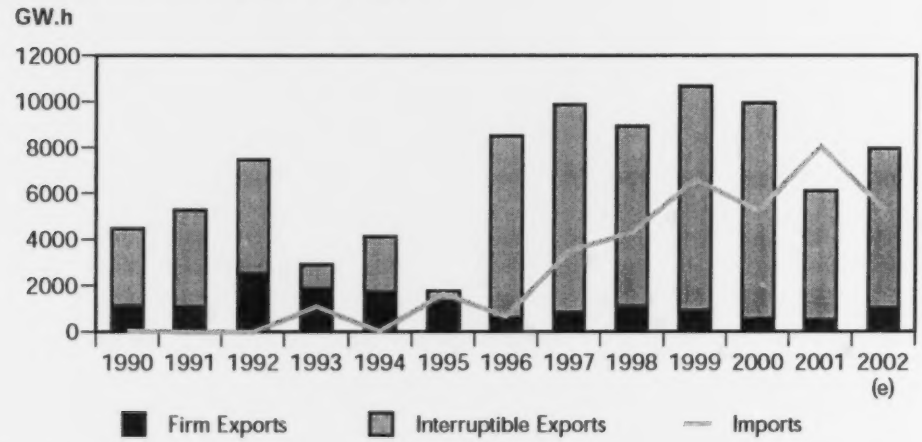
On a seasonal basis, exports have tended to be highest in the third quarter, particularly July and August, corresponding to peak air conditioning loads in California and the U.S. Southwest, and lowest in the second quarter. Since 1996, exports have been facilitated by open access to transmission systems.

Export sales peaked in 2000, with high demand brought about by the California electricity crisis in late 2000 and early 2001. Exports tailed off dramatically in 2001 and 2002. This was the outcome of reduced demand pressure from California (due to increased generation capacity and demand conservation) in the aftermath of its electricity crisis plus surplus water conditions in the Pacific Northwest, the latter especially having an impact in 2002.

Firm exports have generally declined gradually over time reflecting the shorter-term basis on which electricity sales are now transacted. Correspondingly, interruptible sales have increased. Total exports ranged between 10 and 15 percent of generation during the five-year period ending 2001.

FIGURE 3.1.1

British Columbia Exports and Imports



Source: NEB

1 Unless otherwise specified, exports and imports in this report refer to international electricity transfers between Canada and the U.S.

Imports

Imports have risen since 1996 (Figure 3.1.1), again reflecting the opportunities under open access to import power when it is advantageous to do so and to benefit from pricing available during off-peak periods, especially late at night. On a seasonal basis, imports tend to increase during the second quarter to enable replenishment of B.C.'s reservoirs from the spring run-off. In addition, it appears that growth in B.C. power generation has lagged growth in demand in recent years, resulting in an increased requirement for extra-provincial supply, either from Alberta or from the U.S.

With the recent decline in exports and increase in imports, B.C. became a net importer of electricity in 2001 and throughout the first half of 2002. Water reserves were replenished during that period and B.C. once again became a net exporter in the second half of 2002. Preliminary reports indicated that B.C. was selling peak power into the Southwest.

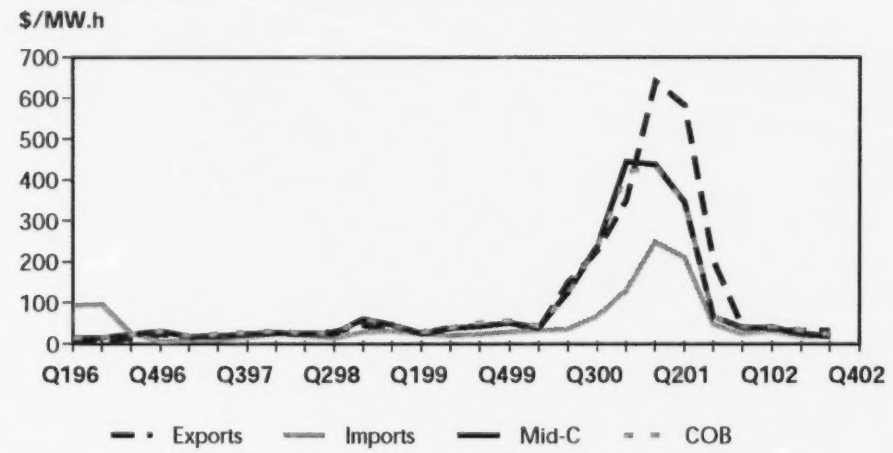
3.1.3 Export and Import Prices[1]

Export Prices

During the last half of the 1990s export prices varied in the range of $20-$50 per MW.h, reflecting the supply and demand conditions in the wholesale markets in the Pacific Northwest (Figure 3.1.2). Export prices tended to be correlated with prices at the Mid-Columbia (Mid-C) trading hub in east-central Washington. Due to the transmission interconnections between Mid-C and California, principally the Bonneville Power Administration's transmission network, Mid-C prices were also correlated with price trends in the California wholesale markets, as indicated by transactions at the California-Oregon Border (COB). This was particularly evident with the steep rise in prices during the California crisis in the latter part of 2000, when prices averaged in the range of $400-$600 on a

FIGURE 3.1.2

British Columbia Export and Import Prices vs. Mid-C and COB



Source: NEB, PIRA. Mid-C and COB prices are average on-peak prices (7:00 a.m. - 11:00 p.m., Monday to Saturday).

1 The prices for exports (imports) in this report reflect the average amount paid per MW.h of electricity exported (imported), based on the quantities and corresponding dollar amounts reported to the NEB.

quarterly basis. B.C. export prices actually rose above Mid-C peak prices. This reflected the capability of B.C. exporters to shape a product to match the super-peak load period, i.e., the mid-afternoon through early evening.

Import Prices

B.C.'s import prices have also been correlated with U.S. wholesale prices. However, import prices have tended to be lower than export prices, reflecting the tendency for B.C. exporters to be able to use their hydro system to import during off-peak periods. Export prices being higher than import prices has allowed B.C. to maintain a substantial revenue surplus in electricity trade with the U.S., even in 2001 when electricity export quantities were lower than import quantities (Figure 3.1.3).[1]

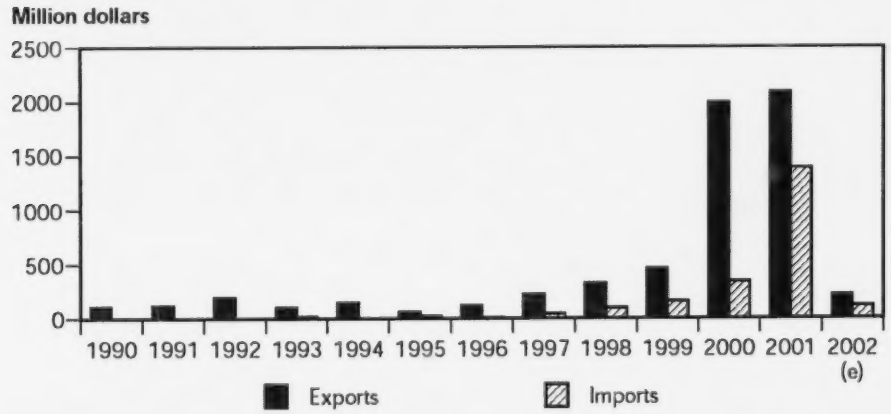
3.1.4 Implications for Domestic Consumer Prices

Export and import prices are determined competitively in regional wholesale power markets, and thus can be quite volatile. On the other hand, retail prices are set by the British Columbia Utilities Commission (BCUC), and will remain frozen until 31 March 2003. The revenue from export sales has allowed BC Hydro, which serves most of B.C.'s residential load, to maintain fixed (and relatively low) prices through payments from export revenue into a rate stabilization fund.

Under the provisions of B.C.'s new energy policy, BC Hydro will again be regulated by the BCUC. At this time it is not clear what the effect on consumer prices will be. According to the policy document, it is expected that there will be upward pressure on prices to cover maintenance expenditures and investment in new transmission and generation. However, consumers will continue to benefit from the low cost of existing hydro generation, referred to as the heritage contract, and the benefits from trade. Further benefits are expected from performance-based regulation and cost

FIGURE 3.1.3

British Columbia Export Revenue and Import Costs



Source: NEB

1 These actual figures and estimates are based on data reported to the NEB. It is possible that, as a result of the inquiry into the operation of the California market during 2000 and 2001, these data may be subject to revision.

efficiencies resulting from having new generation constructed by independent power developers, possibly including new major hydro facilities.[1]

3.1.5 Factors Influencing Future Trade

The capability to export and import electricity has enabled both B.C. and U.S. parties to benefit by having power available when required, and by exploiting the economic opportunities resulting from daily and seasonal diversity. The extent to which exports from B.C. might increase is dependent on the growth in future generation relative to domestic demand and access to export markets.

These trends may well be influenced by B.C.'s. new energy policy, which promotes private sector development of generation. By the creation of the BC Hydro Transmission Corporation, a separate entity from BC Hydro, the policy also promotes improved access to the B.C. grid and IPP participation in U.S. wholesale markets.

Trade might also be augmented through B.C.'s participation in RTO West. As currently proposed, RTO West would cover all or parts of eight states and may include B.C., which joined in the RTO West application to the FERC.[2] Uncertainty stems from the timing of the formation of RTO West, and although B.C. (through BC Hydro) participated in the application, the terms on which it would participate in RTO West have not yet been negotiated.

Apart from RTO developments there is a growing recognition that the expansion of electricity transmission poses regional challenges - including consideration of reliability, commercial feasibility, and the assignment of costs - that require coordination of power systems across the western U.S. and western Canada. Studies were recently conducted for the Western Governors on this issue[3] and BC Hydro has also conducted a study of changes that might be required from its perspective.[4]

3.2 Yukon Territory, Northwest Territories and Nunavut

The large land area and small populations in the Yukon Territory, Northwest Territories and Nunavut have precluded the development of integrated electrical networks. The electric industries in the Territories comprise a mixture of small hydro plants, oil-fired turbines and internal combustion plants located in isolated northern communities and industrial developments. Currently, there are no interconnections with the provinces and no external transfers of electricity.

3.3 Alberta

Alberta has had a competitive wholesale market since January 1996, with the advent of the Power Pool of Alberta. With few exceptions (e.g., power produced for own consumption), all electricity transactions, including international exports and imports and interprovincial transfers must occur

1 *Energy For Our Future: A Plan for BC*, November 2002, PP. 27-30, 37. According to the policy, a public hearing on BC Hydro rates will be held by the end of the fiscal year 2003-2004. The entire plan is expected to be implemented by the end of 2004.

2 FERC News Release, 18 September 2002. The states included in RTO West are Washington, Oregon, Idaho, Montana, Nevada, Utah, Wyoming and a small part of Northern California near the Oregon Border.

3 *Financing Electricity Expansion in the West, A Report to the Western Governors*, February 2002 and *Conceptual Plans for Electricity Expansion in the West, A Report to the Western Governors' Association*, August 2001.

4 *A Briefing on BC Hydro's Transmission Capacity Requirements*, September 2002.

through the Power Pool. The province completed its restructuring process by introducing retail competition on 1 January 2001.

Alberta generates most of its electricity from coal (76 percent in 2001). However, the share of natural gas generation has grown to 20 percent and gas prices have become an important determinant of prices in the Power Pool. Renewables (hydro, wind and biomass) account for the remainder of generation. Over the 1998-2001 period about 2 000 MW were added to generation capacity; these additions were mostly natural gas-fired and represented an increase of 23 percent in total capacity. An additional 5 700 MW, a mix of gas-fired, coal, wind, hydro and biomass projects, have been proposed for completion during the 2002-2006 period.[1]

3.3.1 Transmission Interconnections

Apart from domestic generation, Alberta also has access to other supplies to meet its electricity requirements, including imports from B.C., Saskatchewan and the U.S. Through the B.C. intertie, Alberta and B.C. engage in important trade, on a daily basis, that takes advantage of the difference in the generating technologies in the two provinces. Alberta imports power during peak periods, especially the late afternoon and early evening, and then returns off-peak power. This enables Alberta's predominantly thermal-based generation system to run at a relatively constant, and therefore more efficient, rate through the entire day while B.C.'s predominantly hydro-based system can be operated to accommodate the peak, and then store water behind its dams at night.

Access to the U.S. market is primarily via the intertie to the B.C. transmission grid, since Alberta has no direct link with the U.S. for wholesale power transfers (Figure 2.2). There is also indirect access to the U.S. via an intertie with Saskatchewan. Although both B.C. and Saskatchewan have open access transmission, it has been suggested that exports from Alberta to the U.S. are constrained because of congestion within Alberta and constraints through B.C. and Saskatchewan. This is one reason why there have been proposals for merchant transmission, i.e., a transmission line that would be physically independent from the regulated transmission grid and for which tolls and tariffs would be negotiated between shippers and the transmission line owner.[2]

3.3.2 Exports and Imports[3]

Exports

The key development for exports of electricity from Alberta was the advent of open access transmission starting in 1996, which subsequently enabled Alberta to access the U.S. market through B.C.'s transmission system (BC Hydro). After an initial increase to nearly 200 GW.h in 1997, exports fell off over the next two years in an environment where Alberta's demand was growing, yet new generation was not (Figure 3.3.1). Exports turned upward in 2000 and jumped dramatically to almost 700 GW.h in 2001. This was the result of the demand created during California's electricity crisis, particularly in late 2000 and early 2001, and was accommodated by new generation that came on stream in Alberta. Incremental exports during this period were largely on an interruptible (non-firm) basis.

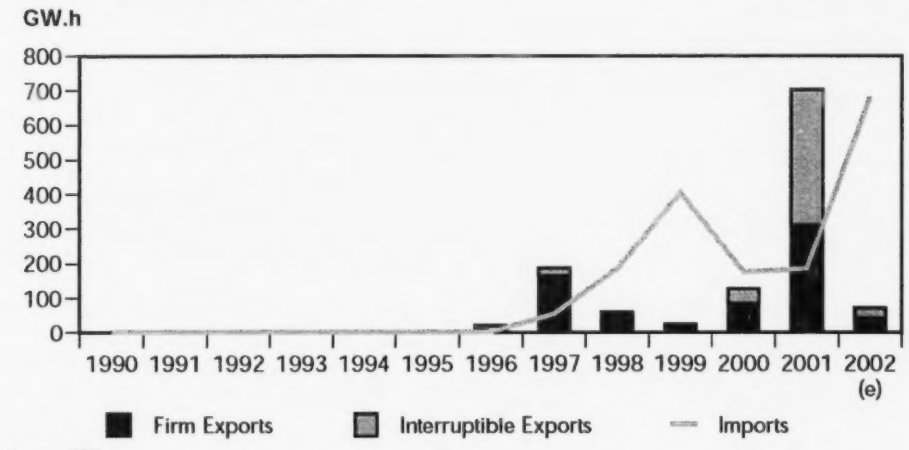
1 Alberta Energy, July 2002.

2 One example of merchant transmission is a current proposal, the Northern Lights project, to move electricity produced in the Fort McMurray area to the Mid-C region in the state of Washington.

3 Unless otherwise specified, exports and imports in this report refer to international electricity transfers between Canada and the U. S.

FIGURE 3.3.1

Alberta Exports and Imports



Source: NEB

Exports declined in 2002, reflecting the supply and demand adjustments in California which started later in 2001, and the bountiful hydraulic conditions which developed in the U.S. Pacific Northwest, particularly over the course of 2002.

In 2001 exports were the equivalent of about one percent of generation. The main export markets were the state of Washington and California. ENMAX (the City of Calgary utility) and Aquila Canada were the largest exporters, while Duke Energy and Enron Capital & Trade exported relatively small amounts.

Imports

Open access to transmission systems has also improved Alberta's ability to import electricity. Imports increased particularly in 1998 and 1999 to help meet Alberta's increasing demand, then subsided as new domestic generation began to affect the supply/demand balance. Imports increased substantially in 2002, as importers took advantage of the availability of low prices in the Pacific Northwest.

3.3.3 Export and Import Prices[1]

Export Prices

During the last half of the 1990s export prices varied in a range of $20-$50 per MW.h (Figure 3.3.2). Although the connection is an indirect one, through the BC Hydro grid, export prices tended to reflect price movements in the Pacific Northwest, as indicated by Mid-C prices, and prices in California.[2] Alberta export prices were correlated with the high prices in California during the 2000-2001 period, when they averaged in the range of $350-$450 per MW.h on a quarterly basis, before declining toward previous levels.

1 The prices for exports (imports) in this report reflect the average amount paid per MW.h of electricity exported (imported), based on the quantities and corresponding dollar amounts reported to the NEB.

2 Refer to section 3.1.3.

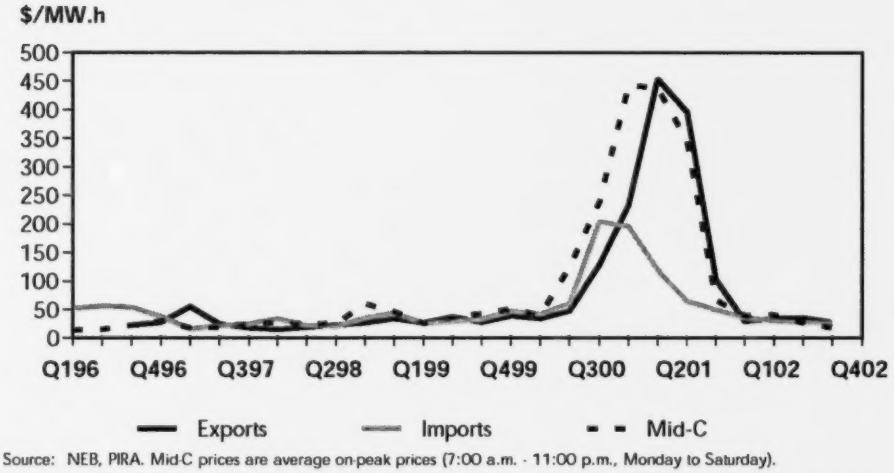
Import Prices

Import prices have also followed wholesale price trends in the western U.S. and have been generally comparable to export prices. The main exception was during 2000 and 2001 when import prices first rose above export prices and then fell substantially below exports. Initially, during this period, imports rose to meet Alberta demand and higher prices had to be paid. Import prices then declined with reduced demand for imports.

The net effect of electricity trade and pricing in 2001 was a substantial surplus of export revenue above import costs of more than $200 million (Figure 3.3.3). For 2002, a small deficit is estimated, as import costs exceeded export revenues.

FIGURE 3.3.2

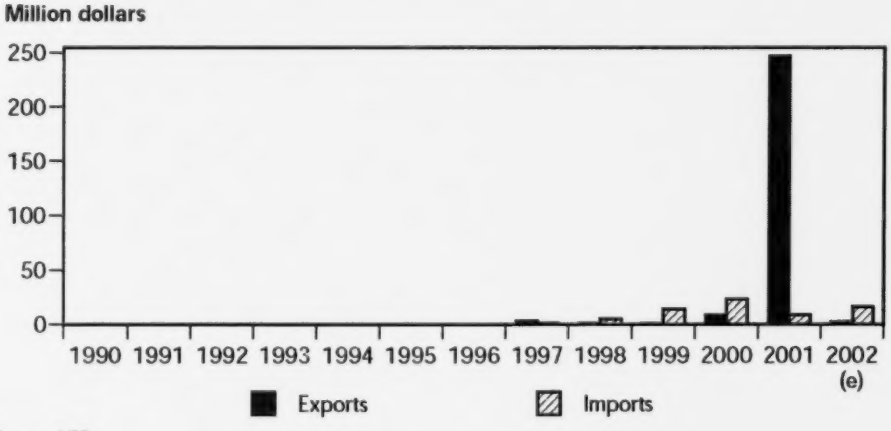
Alberta Export and Import Prices vs. Mid-C



Source: NEB, PIRA. Mid-C prices are average on-peak prices (7:00 a.m. - 11:00 p.m., Monday to Saturday).

FIGURE 3.3.3

Alberta Export Revenue and Import Costs



Source: NEB

3.3.4 *Implications for Domestic Consumer Prices*

In Alberta's restructured market consumers have a number of choices for purchasing electricity. In essence, however, the price paid by the consumer is composed of the Power Pool price, transmission and distribution charges, and miscellaneous charges such as billing, administration and municipal access fees (for use of distribution line right of way).

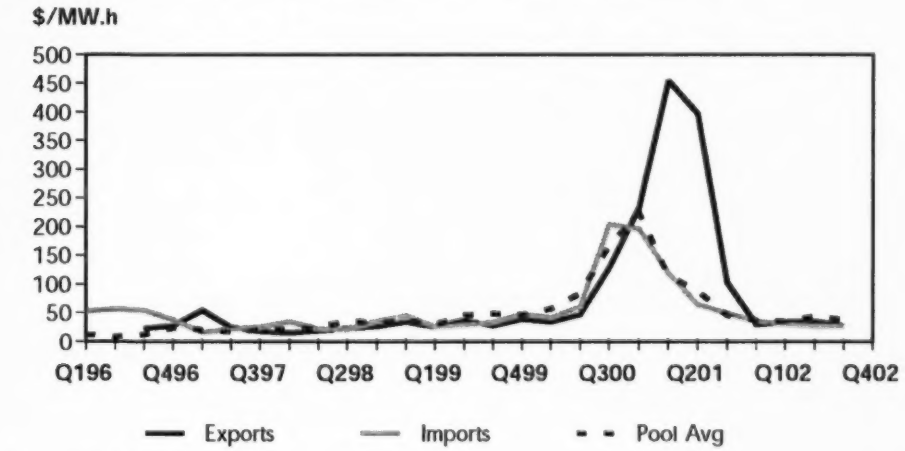
Prices in the Power Pool of Alberta are determined by the bids and offers submitted by market participants. The lowest offer received for the last unit of generation required to meet demand sets the pool price. Comparisons with export and import prices tend to suggest that pricing developments in the U.S. influence the pool price (Figure 3.3.4), as was evident during the price spike in California in 2000-2001.

Prior to December 2000, due to the price setting mechanism employed in the Power Pool, it was possible that imports could set the pool price. However, a change was introduced whereby any incremental cost for imports is included in an uplift charge which is added to the pool price; this averages the cost of imports over all power transacted through the pool, thus modifying the impact of higher cost imports.

The effect of exports on the pool price is less direct. If export prices, established for example in bilateral arrangements, are higher than the pool price, then exporters would bid prices into the Power Pool at zero to ensure their power would be dispatched and would flow to the export customer. While the higher price would not be "seen" in the pool since the generator's bid would not set the pool price, there would be an upward impact on the pool price as increasingly higher cost domestic generation was called on to meet demand in the power pool. Knowledge of the export opportunity might also affect the bidding strategies of the other pool participants. While a strong export market would tend to put upward pressure on the pool price, this could be dampened to the extent that access to the export market is constrained, e.g., by the availability of transmission.

FIGURE 3.3.4

Alberta Export and Import Prices vs. Power Pool of Alberta



Source: NEB, Power Pool of Alberta

Protection from price volatility in the Power Pool is provided to residential and small commercial and small industrial consumers through a Regulated Rate Option offered by their local utility (e.g., EPCOR, ENMAX, and ATCO). For example, the energy price component of the rate paid by residential consumers in ENMAX's service area was 6.1 cents per kW.h in 2002 ($61 per MW.h).[1] There is also the option to take a fixed price over a specified term (e.g., three or five years) or make other similar arrangements with other service providers. Larger commercial and industrial consumers do not have the Regulated Rate Option, but can mitigate price risk either through bilateral contracts or contracting through the forward market, the Alberta Watt Exchange (Watt-Ex).

3.3.5 Factors Influencing Future Trade

It appears that the main factor affecting growth in Alberta exports will be transmission access to the export market. This will require relief of transmission capacity limitations within Alberta and improved transfer capability either through B.C. or Saskatchewan. In its annual assessment of future transmission requirements, the Transmission Administrator (ESBI Alberta)[2] proposed a number of options which took into account future generation additions and transmission additions within the province and at the interprovincial ties. The distribution of costs between domestic and export transmission, was the subject of the Congestion Management Hearings conducted by the Alberta Energy and Utilities Board (EUB) in the second and third quarters of 2002. The EUB determined that the cost of any additional transmission facilities required for electricity exports would be paid entirely by the exporters.[3] In May 2002, the Government of Alberta enunciated five principles of an Export Strategy, indicating a neutral stance with respect to exports while indicating that the interests of Alberta consumers would also be protected.[4]

It has been argued by a number of parties that access to the export market might be improved by joining RTO West. While there is support for this in Alberta, the province has not formally joined in the proposal (which would be a joint effort of Alberta Energy, the Power Pool of Alberta and the Transmission Administrator). Longer term transmission planning on a regional basis would also be an important function of the RTO. The importance of regional planning is recognized in a recent study conducted for the Western Governors, which considers the interdependence between the power systems of Alberta, B.C. and the western states in planning for improved reliability and electricity transfer capability in the entire region.[5]

An important development that could significantly increase Alberta exports is the surplus of electricity that could come about from cogeneration in the Fort McMurray area, which is the centre of oil sands development in Alberta. One proposal is to send the power via a merchant transmission line (the Northern Lights Transmission project) into the Mid-C area.

1 Based on 700 kW.h consumption per month, the energy charge comprises approximately one half of the total electricity bill.

2 ESBI's operations were folded into the Power Pool of Alberta commencing 25 October 2002.

3 EUB News Release, 5 November 2002. Exports include interprovincial transfers and exports to the U.S.

4 Government of Alberta News Release, 29 May 2002

5 Refer to section 3.1.5.

3.4 Saskatchewan

Electricity generation, transmission and distribution in Saskatchewan are mainly carried out by the Saskatchewan Power Corporation (SaskPower). Most electricity is produced from coal-fired generating plants, and some hydro plants, remotely located from population centres; natural gas generation has been increasing in recent years. Saskatchewan's development of generation has historically reflected a policy of building for domestic load growth. On occasion, SaskPower has exported short-term surplus power and sometimes has obtained supplemental power by interprovincial transfers from Manitoba and Alberta and imports from North Dakota to meet unanticipated shortfalls. The electric generation resources in Saskatchewan, Alberta and North Dakota are mostly thermal, in contrast to Manitoba which is hydro based. The diversity of these resources, and the winter peak in Canada versus the summer peak in the U.S., provides opportunities for trade that are beneficial to Saskatchewan and its bordering regions.

3.4.1 *Transmission Interconnections*

Saskatchewan is connected to Alberta by one 230 kV direct current transmission line with a transfer capability of 150 MW in both directions. The interconnections with Manitoba include three 230 kV lines and two 115 kV lines with a total transfer capability of 475 MW from Saskatchewan to Manitoba and 450 MW in the opposite direction. There is one 230 kV line to North Dakota with a transfer capability of 215 MW from Saskatchewan to North Dakota and 165 MW in the opposite direction.[1]

3.4.2 *Exports and Imports*[2]

Exports

Since 1996, when open access was introduced on U.S. transmission systems, there has been a trend toward higher exports from Saskatchewan. Improved access to U.S. markets has also enabled firm export sales to occur (Figure 3.4.1).

In 2001, SaskPower was the only exporter from Saskatchewan. NorthPoint Energy Solutions Inc., a wholly-owned marketing subsidiary of SaskPower, took over that aspect of SaskPower's operations starting 1 November 2001, which coincided with the opening of the SaskPower transmission system and implementation of its Open Access Transmission Tariff.

Imports

Until 1997, Saskatchewan was a net exporter of electricity to the U.S. However, as open access was implemented on U.S. systems, imports increased from less than 100 GW.h in 1996 to more than 800 GW.h in 2001. During the 1997-2002 period, although generation did increase, most of Saskatchewan's growth in electricity demand was met by increased imports from the U.S.[3] Saskatchewan also imports electricity from the U.S. for resale into Alberta.

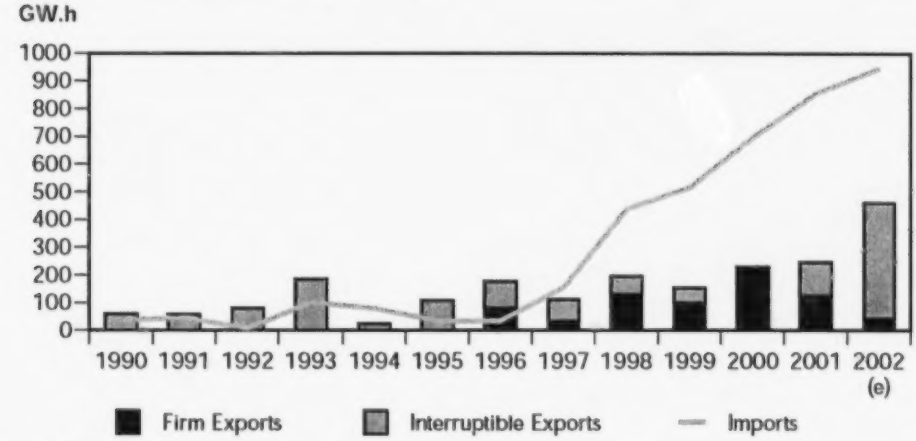
1 Transfer capabilities are as of November 2002; these are reviewed regularly and are subject to change. Transfer capability at any point in time depends on a reliability margin and existing transmission commitments. There is also an inter-relationship between Manitoba to Saskatchewan and North Dakota to Saskatchewan power flows that means the transfer capabilities noted here cannot be supported simultaneously. Source: SaskPower.

2 Unless otherwise specified, exports and imports in this report refer to international electricity transfers between Canada and the U.S.

3 In 2001, generation accounted for about 91 percent of domestic consumption. Most of the shortfall was met by imports from the U.S. Source: Statistics Canada, 57-001.

FIGURE 3.4.1

Saskatchewan Exports and Imports



Source: NEB

3.4.3 Export and Import Prices[1]

Export Prices

The prices obtained for Saskatchewan exports have generally followed the trend of wholesale prices in the adjacent market area in the U.S., as represented by prices in the northern part of the Mid-Continent Area Power Pool (MAPP). The correlation is particularly evident during 2000 and 2001, when prices rose during the California electricity crisis and declined in the aftermath (Figure 3.4.2).

Import Prices

Import prices have tended to be much less volatile, and lower, than export prices over the past five years, remaining in the range of $20 to $40 per MW.h. This reflects two main factors: the low cost of power generation in the U.S. MAPP Area, based mostly on coal-fired generation; and the low cost of electricity imports in off-peak periods, which are not subject to the higher on-peak prices pertaining to exports.

In recent years the combination of export/import trends and prices has resulted in total import costs exceeding export revenues, in the order of $5 million to $15 million per year (Figure 3.4.3)

3.4.4 Implications for Domestic Consumer Prices

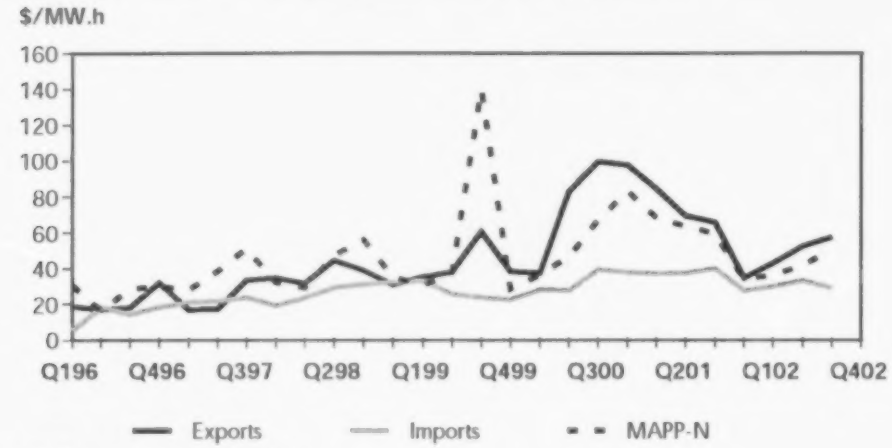
Consumer rates, or prices, in Saskatchewan are set by SaskPower and are subject to review by the Saskatchewan Rate Review Panel and approval by Cabinet. Import costs that are greater than export revenues might indicate that, other things equal, domestic rates should rise to recover these costs from electricity consumers. Increased import costs for SaskPower accounted for a small portion of a two percent rate increase on 1 April 2001 and an additional 4.5 percent increase on 1 January 2002. These were the first increases since 1994.[2]

1 The prices for exports (imports) in this report reflect the average amount paid per MW.h of electricity exported (imported), based on the quantities and corresponding dollar amounts reported to the NEB.

2 Saskatchewan Power Corporation, *2001 Annual Report*.

FIGURE 3.4.2

Saskatchewan Export and Import Prices vs. MAPP North*

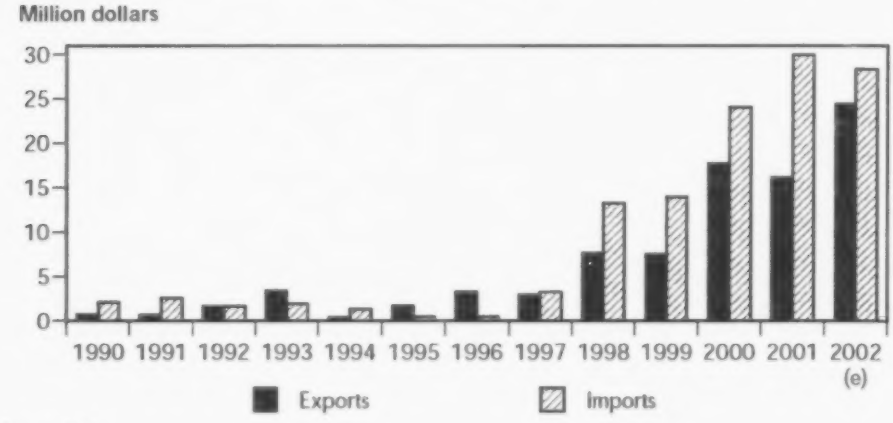


* Mid-Continent Area Power Pool - North

Source: NEB, PIRA. MAPP North prices are average on-peak prices (7:00 a.m. - 11:00 p.m., Monday to Saturday).

FIGURE 3.4.3

Saskatchewan Export Revenue and Import Costs



Source: NEB

SaskPower purchases energy when economic to offset the cost of in-province generation, or to resell to other jurisdictions. This activity helps to keep domestic rate increases to a minimum.

3.4.5 *Factors Influencing Future Trade*

In recent years, Saskatchewan has been a net importer of electricity and has utilized its interconnections with the U.S., and neighbouring provinces, to supplement its own generation in order to meet provincial requirements. Imports could decline in future years if other low-cost generation in Saskatchewan is developed, or low-cost transfers from Manitoba increase.

Notwithstanding the generation outlook, it appears that it would be in Saskatchewan's interest to maintain access to U.S. markets, either from the standpoint of an exporter or importer. SaskPower has implemented an Open Access Transmission Tariff, thus providing access for third parties to the provincial electricity grid. To the extent these interests could be furthered by participation in an RTO, Saskatchewan seems to be most naturally aligned with an RTO in the U.S. Midwest, e.g., the Midwest Independent System Operator (MISO). However, as of November 2002, Saskatchewan had not made an application to be part of the MISO.

3.5 Manitoba

Manitoba has abundant hydro resources with nearly 5 000 MW of hydraulic generating capacity installed, and approximately 95 percent of the province's electricity generated by hydro power. This means that Manitoba's export levels are largely determined by water levels. Approximately 30 percent of the power generated in the province is exported to or through Minnesota and North Dakota, which makes Manitoba the province with the highest proportion of electricity exports.

3.5.1 Transmission Interconnections

Manitoba is connected to the United States by four international power lines. In 1970 a 230 kV transmission line was built between Winnipeg, Manitoba and Grand Forks, North Dakota. A second 230 kV line connected Manitoba to Duluth, Minnesota in 1976. Manitoba's transfer capability doubled when a 500 kV line was installed in 1980 to connect with additional utilities in Minnesota. Manitoba Hydro is currently constructing the Manitoba portion of a 230 kV line between its Glenboro Station in Southern Manitoba, and Rugby, North Dakota. Manitoba Hydro, the company responsible for virtually all of the power exports from the province, estimates its maximum transfer capability with the Mid-Continent Area Power Pool is 2 175 MW.

Manitoba also has several interconnections with neighbouring provinces: three 230 kV lines and two 115 kV lines connecting to Saskatchewan (maximum transfer capability of approximately 450 MW); and two 230 kV lines and a 115 kV line connecting to Ontario (maximum transfer capability of approximately 300 MW). Interprovincial lines are run closer to their transfer capacity than international lines, so Manitoba would be more likely to face constraints when arranging for interprovincial trade, if interprovincial trade were to increase rapidly.

In February 2002 the Midwest Independent System Operator, Inc. (MISO) began full operations, with Manitoba Hydro participating via a Coordination Agreement. According to the framework laid out in the Coordination Agreement, Manitoba Hydro is treated as a virtual MISO member since, as a Crown corporation, Manitoba Hydro may not transfer operational control over its facilities to a foreign entity. MISO will facilitate Manitoba Hydro's access to the coordinated operations and transmission services of participating companies in the Mid-Continent Area Power Pool. According to Manitoba Hydro, the Coordination Agreement will continue to ensure Manitoba does not face transmission trade barriers in the U.S.

3.5.2 Exports and Imports[1]

Exports

During the late 1980s Manitoba's demand was growing close to its supply, so the Limestone hydrogenerating station was constructed to ensure that Manitoba would not face electricity shortages. As units of the Limestone station were brought online in the early 1990s, exports increased (Figure 3.5.1). Since consumption tends to increase steadily, while hydro capability is added in large blocks, immediately after a hydro facility has been built a utility typically has excess power available for export. As demand grows, this surplus diminishes over time until the utility constructs another generating facility.

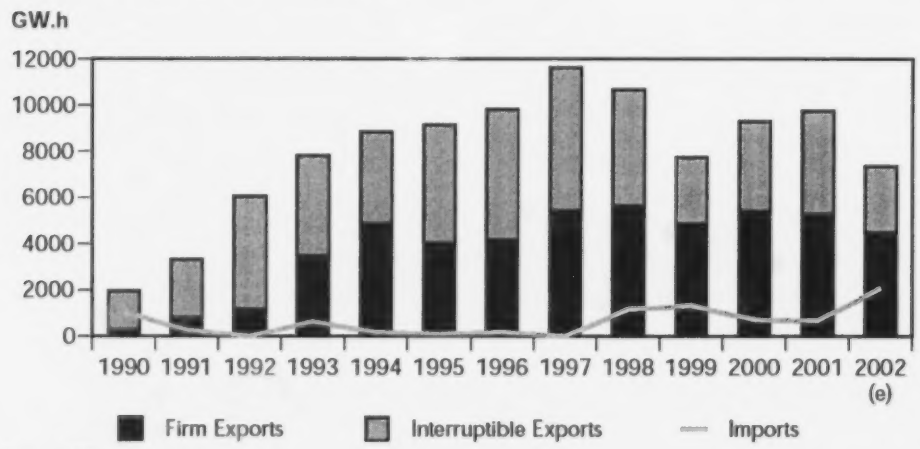
From 1994 through 2002 annual exports averaged 9 400 GW.h, with fluctuations mainly caused by varying water levels. For example, in 1997 Manitoba experienced flooding, so water levels were high in 1997 and into 1998, resulting in additional power available for export. Accordingly, Manitoba's exports reached a record high of nearly 12 000 GW.h in 1997. Conversely, in 1999 water levels were low so the province reduced exports, and increased imports to ensure adequacy of supply for Manitobans. Water levels were low in 2002, again resulting in decreased exports.

Manitoba's domestic system load is approximately 1 000 MW higher in the winter than it is in the summer. Therefore, assuming normal water flows, Manitoba has excess hydropower available in the summer. Summer is also the time when demand in adjacent U.S. market peaks due to air conditioning loads. Accordingly, net exports tend to peak in the third quarter and are usually lowest in the first quarter. When trading partners have different seasonal demands for electricity, the trade is known as "seasonal diversity exchange."

In the early 1990s, Manitoba's exports were primarily based on interruptible arrangements. In the mid-1990s the balance shifted so that the province exported approximately equal amounts of firm and interruptible power. Since 1998, firm exports have outweighed interruptible exports in an

FIGURE 3.5.1

Manitoba Exports and Imports



Source: NEB

1 Unless otherwise specified, exports and imports in this report refer to international electricity transfers between Canada and the U.S.

approximately 60:40 split. Export revenues are a large portion of the Province's electricity revenues, and firm contracts help to provide stability and certainty in this regard.

Imports

Manitoba imports only a small amount of power, approximately one tenth of the power it exports. Imports are used in concert with exports to enable both Manitoba and its trading partners to benefit from reserve sharing and coordination of planning and operation. Reserve sharing involves agreements for mutual generation support so that the need for new power plants is decreased or deferred. Coordination of planning and operation involves cooperation between utilities, mainly in generation facility planning, operation and maintenance, to reduce investment requirements and distribute maintenance outages so that system operations are optimized.

3.5.3 Export and Import Prices[1]

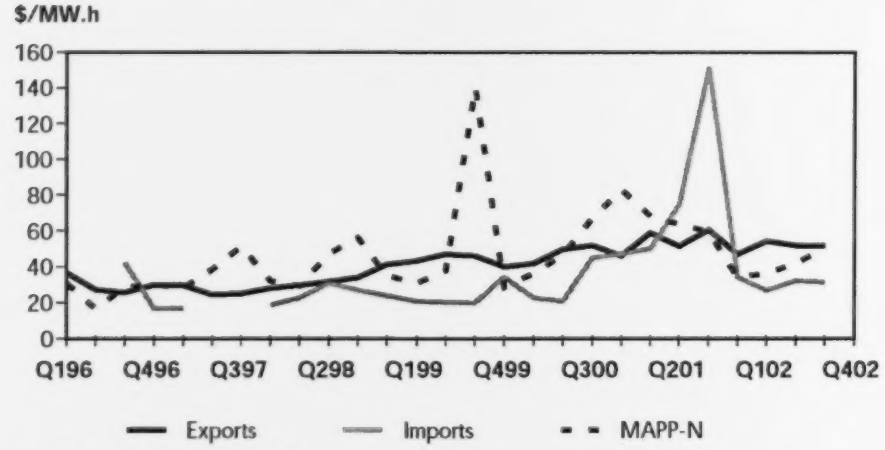
Manitoba export and import prices are generally in the same range as wholesale prices in MAPP-N, the northern part of the Mid-Area Continent Power Pool (Figure 3.5.2). Approximately 95 percent of exports from Manitoba are transacted through bilateral contracts. The long-term nature of these contracts results in Manitoba missing the highs and lows that tend to occur on the spot market, so Manitoba's average export prices exhibit more stability than MAPP-N prices.

Export Prices

Manitoba's export market is the Mid-Continent Area Power Pool. The MAPP market is characterized by low costs of production and, consequently, relatively lower prices than other areas such as New York and California. The U.S. utilities generate power from low-cost coal, and due to a relatively low population density, infrastructure is not as difficult to site as in some other regions. For these reasons,

FIGURE 3.5.2

Manitoba Export and Import Prices vs. MAPP North*



* Mid-Continent Area Power Pool - North

Source: NEB, PIRA. MAPP-North prices are average on-peak prices (7:00 a.m. - 11:00 p.m., Monday to Saturday).

1 The prices for exports (imports) in this report reflect the average amount paid per MW.h of electricity exported (imported), based on the quantities and corresponding dollar amounts reported to the NEB.

Manitoba's average export prices tend to be lower than average Canadian electricity export prices. Manitoba's export prices have increased from an average of $18 per MW.h in 1990 to approximately $51 per MW.h in 2002.

Import Prices

Manitoba's average import prices are consistently lower than average Canadian electricity import prices because Manitoba has plentiful hydro resources to meet its power needs, and tends to import electricity only at low prices and usually during off-peak hours. Since 1990, average annual import prices have typically been less than $30 per MW.h.

3.5.4 Implications for Domestic Consumer Prices

The vast majority of electricity in the province is generated from hydro power projects, which have high capital costs, and low marginal costs of production. Manitoba produces excess hydro power at low cost, exports it, and uses the revenue to reduce the fixed costs domestic consumers pay. Manitoba's export revenues have increased due to increased market prices as well as increased quantities which are the result of surplus generation (Figure 3.5.3).

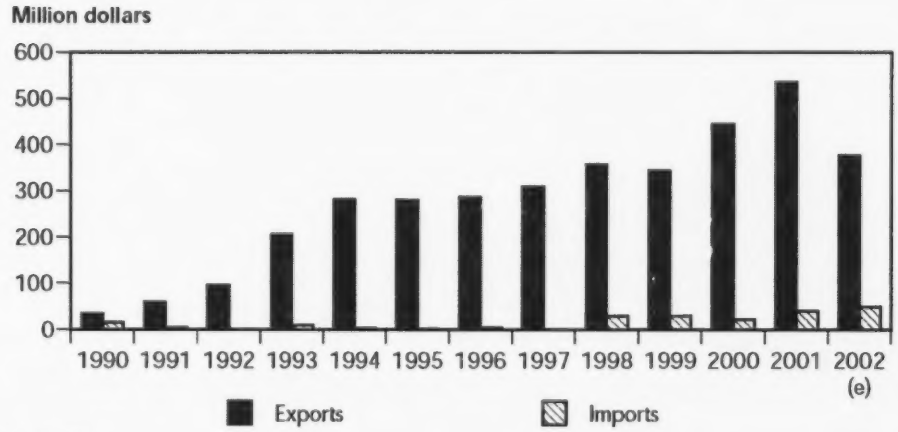
Manitoba Hydro's Power Smart energy conservation strategy assists customers in using energy more efficiently so that surplus energy can be exported outside the province. Export revenues reduce the price of power charged to Manitobans by as much as 30 percent. In fact, Manitoba Hydro reports that it has the lowest overall rates in Canada and among the lowest in the world.

3.5.5 Factors Influencing Future Trade

Manitoba Hydro is considering two hydroelectric projects to take advantage of strong, profitable markets in the United States and Canada, the 200 MW Wuskwatim and the 620 MW Gull generating station projects. These proposed projects would not be completed for several years; however, large blocks of power could become available, and the surplus could be exported if there is sufficient transmission.

FIGURE 3.5.3

Manitoba Export Revenue and Import Costs



Source: NEB

U.S. utilities may be interested in purchasing additional hydro power to meet requirements for renewable portfolio standards. Implementation of the Kyoto accord could provide an incentive for sales within Canada, to the extent that Canadian utilities attempt to reduce greenhouse gas emissions.

3.6 Ontario

Currently Ontario imports power to meet its peak demand, and to generate additional revenue by exporting available surplus power when demand and prices are high in the U.S. Although the province exported as much as nine percent of the power it generated (in 1994), since the 1997 lay-up of several nuclear units, exports and imports have each averaged just two percent of generation.

3.6.1 Transmission Interconnections

The Independent Electricity Market Operator (IMO) estimates Ontario has 6 000 MW of interconnected transmission capacity with other provinces and states. Connections to New York include two 69 kV lines, one 115 kV line, four 230 kV lines, and two 345 kV lines. Ontario is connected to Michigan by a 120 kV line, a 230 kV line, and two 345 kV lines and to Minnesota by a 115 kV line. Historical power flow statistics show limited periods of transmission constraints on the international lines. This implies that Ontario has the opportunity to increase power flows to the United States during periods of price differentials if and when spare generating capacity is available. Ontario is also interconnected with neighbouring provinces: two 230 kV lines and a 115 kV line connect to Manitoba; and five 230 kV lines and four 115 kV lines connect to Québec.

Ontario straddles the Northeast and the Midwest and the IMO has been involved in discussions with prospective RTOs in both regions. The IMO believes that the allocation of RTO functions is straightforward if FERC's standard market design is adopted. Although Ontario would need to make some changes to be fully compatible with either RTO, there are potential benefits, including shared reserves, coordinated scheduling of transactions, elimination of export transmission tariffs, coordinated planning, joint assessment of interconnection projects near borders, and a common energy day-ahead market. By joining or coordinating with either or both RTOs, Ontario could reduce existing or future barriers to trade.

Hydro One and TransÉnergie proposed the Lake Erie Link Project, a submarine cable under Lake Erie joining the Ontario transmission grid with grids in Pennsylvania and/or Ohio. The project developers have considered responses received from bidders as a result of the initial phase of the open season process, and have decided to delay the current project schedule and postpone the associated project development work to allow sufficient time for continuing discussions with all potential buyers. It is not yet known whether the project will ultimately prove to be commercially viable.

3.6.2 Exports and Imports[1]

Exports

The majority of Ontario's exports are sold on an interruptible basis on the spot market. The province exports a small amount of power on a firm basis, approximately 300 GW.h per year. Historically, exports peaked in the third quarter as surplus energy was exported to meet U.S. air-conditioning demand. However, Ontario's consumption pattern has been changing in response to the greater use of

1 Unless otherwise specified, exports and imports in this report refer to international electricity transfers between Canada and the U.S.

air conditioning in the province. Although a significant winter peak still occurs, Ontario's domestic demand now peaks in the summer, leaving less surplus energy available for summer export.

Throughout most of the early 1990s Ontario had spare capacity due to the addition of new generation facilities, such as the Darlington nuclear plant, and lower than expected domestic demand. In 1997, Ontario Power Generation laid up four units at Bruce A and four units at Pickering A as part of its nuclear refurbishment program.[1] Interruptible export levels decreased after the lay-up and averaged just 3 300 GW.h annually from 1997 to 2002 (Figure 3.6.1). During these years the province alternated between being a net exporter and a net importer as a result of its tight supply and demand balance.

Relatively inexpensive hydro-generated electricity from Manitoba and Québec that is sold into the Ontario market may supplement the amount of electricity available for export to the U.S. At times Ontario maintains a net exporter status with the U.S. while the province is a net importer when interprovincial power flows are considered.

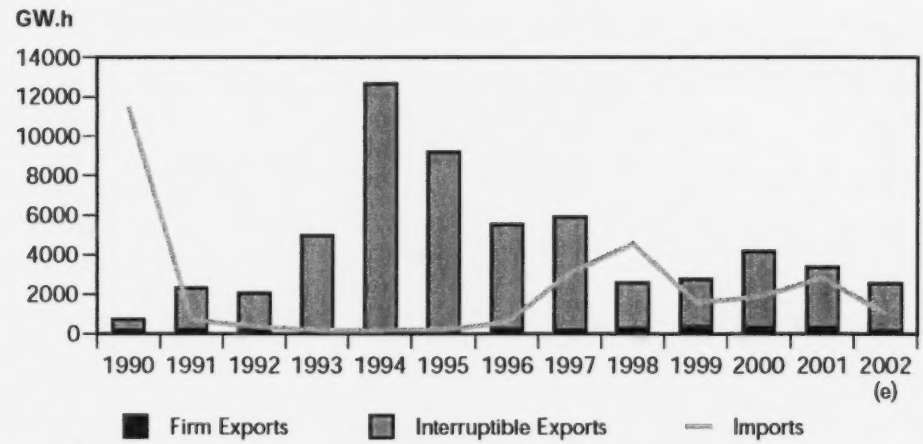
Imports

In 1990 Ontario imported nearly 12 TW.h of electricity to offset reduced nuclear plant production caused by extended unit outages. Imports were quite low from 1991 through 1996 while Ontario had spare generating capacity. Following the nuclear lay up in 1997, Ontario once again increased its imports to meet domestic demand. From 1997 through 2002 annual imports averaged 2 500 GW.h compared to an average of 300 GW.h annually in the preceding five-year period.

Imports have historically peaked in the fourth quarter, corresponding with high demand in Ontario for the heating season. This pattern is likely to change with the new summer peak in Ontario. For example, in 2001 imports peaked in the third quarter and from June through September 2002 imports helped Ontario to satisfy air conditioning demand through abnormally hot weather.

FIGURE 3.6.1

Ontario Exports and Imports



Source: NEB

1 These eight units have total capacity of 5 100 MW. While the timing is uncertain, plans are that about 3 500 MW will be returned to service, excluding two units at Bruce A.

3.6.3 Export and Import Prices[1]

The prices for interruptible exports and imports are generally in line with wholesale prices in western New York state and the PJM interconnection. Since market opening, prices in the IMO-administered market have also moved with wholesale prices in adjacent U.S. markets (Figure 3.6.2).

Export Prices

In the first half of the 1990s export prices were lower than import prices. This suggests that Ontario was selling power during off-peak periods when prices were relatively lower. Ontario's generation mix includes a number of nuclear and thermal generating facilities which must run around the clock, resulting in surplus power being available during off-peak hours. After the nuclear lay-up in 1997, Ontario's export prices increased and began to exceed import prices. From 1990 through 1997 export prices averaged $27 per MW.h but from 1998-2001 export prices averaged $61 per MW.h, reflecting the tighter supply conditions. In 2002, export prices decreased to approximately $40 per MW.h which suggests Ontario's exports were more limited to off-peak periods.

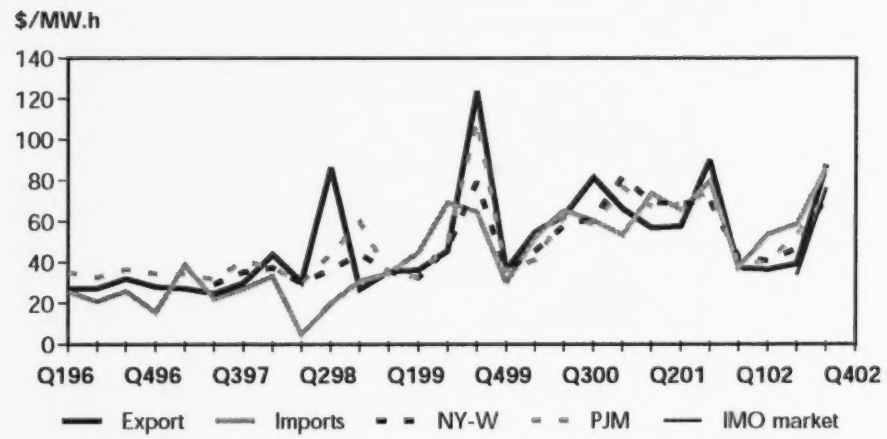
Import Prices

Import prices increased sharply from $22 per MW.h in 1998 to approximately $70 per MW.h in 2001 and 2002 due to tight supply in the U.S. Northeast and Ontario's reliance on imports to meet demand during peak periods.

Over the past decade, export revenues were generally greater than the amount paid for imports, so net revenues were positive. However, export revenues were approximately the same as import costs in 2001 and 2002 (Figure 3.6.3.)

FIGURE 3.6.2

Ontario Export and Import Prices vs. U.S. Northeast and IMO Prices

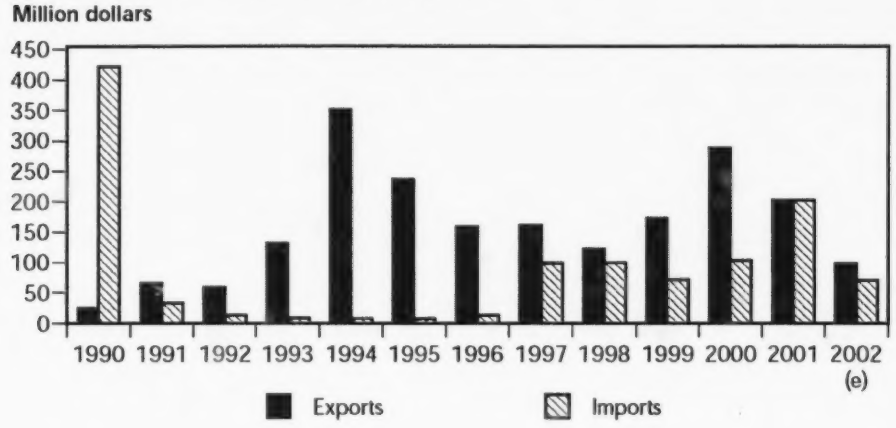


Source: NEB, IMO, PIRA. New York-West and PJM prices are average on-peak prices (7:00 a.m. - 11:00 p.m., Monday to Friday).

1 The prices for exports (imports) in this report reflect the average amount paid per MW.h of electricity exported (imported), based on the quantities and corresponding dollar amounts reported to the NEB.

FIGURE 3.6.3

Ontario Export Revenue and Import Costs



Source: NEB

3.6.4 *Implications for Domestic Consumer Prices*

Currently Ontario has a competitive wholesale electricity market administered by the IMO. Generators offer power into the pool and the IMO dispatches the lowest price generators first, whether inside or outside Ontario, and moves up through the more expensive offers until it has dispatched enough power to meet demand. The highest offer that is accepted determines the pool price. Market participants may bid to take energy out of the Ontario market and offer it into higher-priced U.S. markets if opportunities exist. Parties can make bilateral contracts, for which the IMO will net the scheduled amounts out of the settlements with the parties.

During periods of high demand, expensive import offers must often be accepted to ensure that Ontario has enough power to meet its needs. For example, on 2 July 2002 the hourly Ontario Energy Price peaked at $471 per MW.h but import prices were as high as $2000 per MW.h. To ensure expensive imports do not drive up the prices consumers must pay, the IMO does not allow import offers to determine the energy price. Instead the price is determined by Ontario bids and offers. Before a given hour, the IMO determines the amount of imported power it will need for the hour, and accepts the offers for that amount of imports. Those imports are then sold into the pool for the hour, at the agreed upon price. A separate charge (an uplift charge) is assessed and added to wholesale prices to recover the costs of the imports.

Effective 11 November 2002, the Government of Ontario has capped the energy component of retail prices at 4.3 cents per kW.h or $43 per MW.h.[1] This price freeze is retroactive to 1 May 2002, and will remain in place until 2006. The intent is to protect Ontario consumers from the price volatility in wholesale markets.[2]

1 The price cap applies to residential consumers, small commercial consumers and other designated consumers (e.g., schools, post-secondary institutions, hospitals, nursing homes and charities).

2 To the extent that wholesale prices in the IMO-administered market exceed $43 per MW.h a source of funds must be found to make up the price difference. One source is excess revenue from sales made by Ontario Power Generation, pursuant to the Market Power Mitigation Agreement, which is an important element of Ontario's restructured market.

3.6.5 Factors Influencing Future Trade

A number of companies have exported electricity out of Ontario, primarily the former Ontario Hydro and its successor companies, as well as Abitibi Consolidated, Canadian Niagara, Canadian Transit, Cornwall Electric, and the Detroit and Windsor Subway. Since the market was opened to competition on 1 May 2002, several marketers began to trade in the Ontario market, including Aquila Canada, Conectiv Energy, Coral Energy, EPCOR Merchant, Mirant Americas, PG&E Energy Trading, and Powerex Corporation. It is expected that non-discriminatory access and a well-functioning market would facilitate the involvement of more market players in the future.

Ontario's principal trading partners are New York, Michigan and Minnesota. Recently, moderate demand in New York has made surplus power available for sale to Ontario, which has helped to meet load requirements. If demand growth resumes in the U.S. Northeast before Ontario's nuclear capacity is returned to service, Ontario will face a tighter supply situation which would result in upward price pressure.

Nuclear and coal generation dominate electricity production in Ontario, even though several nuclear units are laid up. When the nuclear units are brought back online, as expected over the next few years, the amount of excess electricity Ontario has available for export will increase for several years, until demand catches up with supply levels. However, the Select Committee on Alternative Fuel Sources, an all-party legislative committee has recommended that the province assess the feasibility of converting all OPG coal and oil-fired generating stations to natural gas. Another recommendation is to mandate the closure of the OPG Atikokan and Thunder Bay coal-fired generating stations by 2005 and all remaining coal or oil-fired generating stations by 2015. These measures, if implemented, would reduce the amount of power available for export.

3.7 Québec

Québec accounts for about 30 percent of total Canadian generating capacity and its electricity generation is predominantly hydro-based. In 1997, the vertically integrated utility, Hydro-Québec (HQ), a wholly-owned corporation of the Government of Québec, complied with FERC Order 888 reciprocity requirements. As a result, a wholesaler licence was issued to HQ Energy Services (U.S.), a subsidiary of HQ. The licence allows direct access to the U.S. wholesale market and requires Québec to provide access to its wholesale market. In 2000, HQ set up an in-house energy trading floor so that it could participate more fully in northeastern U.S. markets. In 2001, HQ was restructured into four divisions: HQ Distribution; HQ TransÉnergie (already established in 1997); HQ Production; and HQ Engineering, Procurement and Construction. HQ Production generates electricity and sells it to wholesale markets both inside and outside Québec.

3.7.1 Transmission Interconnections

At year-end 2001, HQ TransÉnergie had 15 interprovincial and international interconnections with neighboring systems, with a total transfer capability of 7 400 MW. Québec's transmission grid is unique in Canada in that it has a 450 kV HVDC line to New England and a 765 kV line which delivers power from Chateauguay to New York State. Export transfer capacity amounts to 2 300 MW to New England and 2 125 MW to New York. Transmission capacity has been adequate to handle historic levels of exports. Occasionally, Québec's delivery to these markets can be constrained due to transmission limits and periodic congestion south of the border. These problems also limit the import transfer capacity to Québec. To ensure grid reliability, HQ adheres to NERC reliability standards and

TransÉnergie is a member of the Northeast Power Coordinating Council (NPCC).[1] TransÉnergie's network also allows the wheeling in and through of electric power.

3.7.2 Exports and Imports[2]

Exports

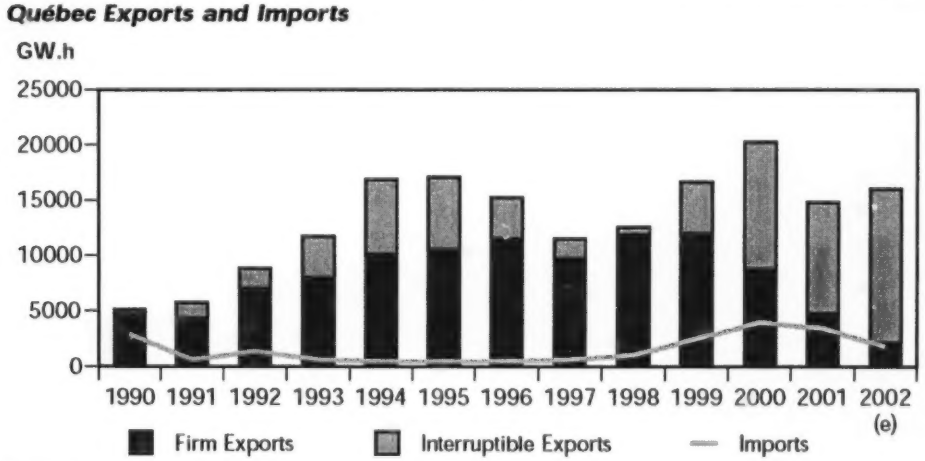
Québec has historically registered the highest electricity exports among all provinces. Its share of total Canadian electricity exports has generally exceeded 30 percent, with an all-time peak of 42 percent in 1995. Since the opening of the northeastern U.S. wholesale markets, Québec's exports to the U.S. grew significantly from 11.5 TW.h in 1997 to a peak of 20.2 TW.h in 2000. Exports declined to 14.6 TW.h in 2001 and were estimated to rise in 2002 (Figure 3.7.1). The year-over-year fluctuation in exports is partly attributable to variable hydraulic conditions. Exports account for 8-10 percent of total provincial generation.

HQ holds 16 out of 22 permits issued to companies exporting from Québec. HQ Energy Services (U.S.) sells power generated by HQ at the Québec border, and buys and sells electricity in the U.S. It buys U.S. power at certain times of day for the Québec market, particularly during nightly off-peak hours. Québec's main export markets are New England and New York State. These markets have registered rapid growth in electricity demand and a significant increase in new natural gas-fired generating capacity in recent years.

Québec's strong electricity export position reflects the abundance of hydraulic resources especially in northern Québec, the availability of low-cost hydroelectricity surpluses, as well as proximity and access to the rapidly growing northeastern U.S. markets. Québec's competitive strength is further enhanced by its water storage capability. The reservoirs provide HQ with supply flexibility, due to the fact that hydro generating units can start and generate electricity more quickly than thermal units. Moreover, the potential energy can be stored and produced when it is most needed.

FIGURE 3.7.1

Québec Exports and Imports



Source: NEB

1 The NPCC is one of the NERC administrative regions.

2 Unless otherwise specified, exports and imports in this report refer to international electricity transfers between Canada and the U.S.

Historically, exports were mainly associated with long-term firm supply contracts, which for the most part, had expired by year-end 2001. As most contracts expired and were not renewed, the share of firm exports has declined. As a result of declining firm exports, HQ has relied on non-firm exports and trading activities to maintain its export market share and revenue. In 2001, non-firm exports accounted for 68 percent of total exports, compared to 15 percent in 1997.

Imports

Prior to 1997, Québec's electricity imports reflected tight supply conditions in Québec, economy interchanges and/or diversity exchanges with neighboring utilities. Due to higher levels of trading activities in recent years, imports have increased substantially from 0.6 TW.h in 1997 to more than 3 TW.h in 2000 and 2001. Most imports are being used in either brokerage transactions or for resale during peak periods.

Due to increased trading activities, net electricity exports have not increased significantly in recent years compared to the period prior to wholesale market opening in the U.S. Northeast. Since 1997, net exports have varied between approximately 11 and 16 TW.h annually.

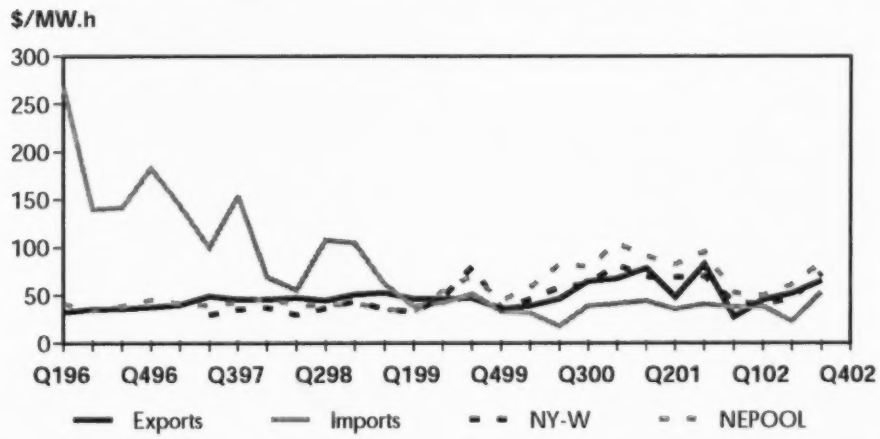
3.7.3 Export and Import Prices[1]

Export Prices

Export prices remained relatively stable although varying in the range of $35-$50 per MW.h over the 1996-1999 period. Over the last two years, export prices have been particularly volatile, fluctuating in the range of $30-$85 per MW.h (Figure 3.7.2). These price fluctuations reflect the volatility inherent to spot electric power markets, real-time trading and arbitrage activities, as well as short term supply and demand conditions.

FIGURE 3.7.2

Québec Export and Import Prices vs. U.S. Northeast Prices



Source: NEB, PIRA. New York-West and NEPOOL prices are average on-peak prices (7:00 a.m. - 11:00 p.m., Monday to Friday).

1 The prices for exports (imports) in this report reflect the average amount paid per MW.h of electricity exported (imported), based on the quantities and corresponding dollar amounts reported to the NEB.

Since 1998, export prices have followed a trend similar to those of NEPOOL and New York. While prices for NEPOOL and New York are spot prices, the export price includes a mixture of contracted, spot and forward prices. Prices for firm exports tend to be higher than for non-firm exports, which reflects a premium associated with security of supply.

Import Prices

Since 1999, import prices have generally been lower than export prices, varying mostly in the range of $25-$45 per MW.h. Imports generally occur during off-peak periods when prices are relatively low.

3.7.4 Implications for Domestic Consumer Prices

Electricity exports are a major source of revenue for HQ. Export revenue reached a record level of about $1.1 billion in 2000 as a result of relatively high export quantities and high prices. Export revenues declined in 2001 and 2002, but remained significantly higher than historical levels (Figure 3.7.3).

End-use electricity prices in Québec are among the lowest in Canada. Historically, export revenues allowed the vertically-integrated HQ to keep domestic prices lower than they otherwise would be. With the passage of provincial Bill 116, the "commodity" component has been set by the Québec government at 2.79 cents per kW.h for the "heritage pool" of 165 TW.h. The price for energy supplied above that amount is determined by the cost of acquisition through a competitive process.

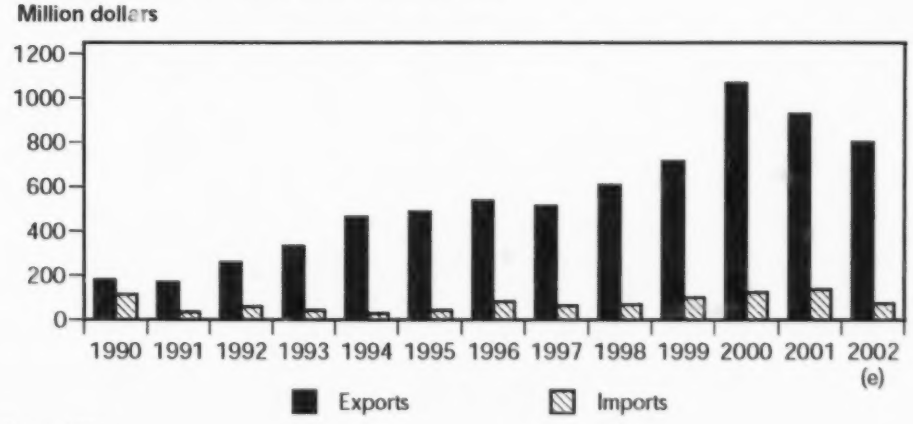
Only the transmission and distribution components are regulated by the Régie de l'énergie. Under this pricing regime, end-use prices in Québec are not directly influenced by fluctuations in either export or import prices. Québec's imports are negligible relative to Québec electricity consumption; therefore, the impact of relatively high import costs on electricity rates is insignificant.

3.7.5 Factors Influencing Future Trade

Québec's hydroelectric resources and large generating capacity enable it to produce clean renewable energy at low cost. Surplus electricity supply in Québec allows it to continue to play an active role in

FIGURE 3.7.3

Québec Export Revenue and Import Costs



Source: NEB

export markets. Its geographic proximity to the northeastern U.S. market offers numerous export and trade opportunities. Several interconnections which can accommodate higher trade levels on Québec's side provide direct access to the northeastern U.S. markets. With unconstrained and economical access to the U.S., HQ appears to be well positioned to expand its trading activities.

Since Québec's generating capacity is predominantly hydro-based, the amount of surplus energy available for exports depends to a large extent on the level of precipitation and Québec's overall supply and demand conditions. The province will likely see significant hydro and, to a lesser extent, gas-fired capacity additions over the next few years. Québec is also actively pursuing joint development of the Gull Island project with Newfoundland and Labrador. With RTO developments in the U.S. Northeast and the resulting reduction in transmission rate pancaking, and eventual removal of transmission congestion in the U.S. portion of NPCC, Québec's exports and imports will likely increase in the coming years.

3.8 New Brunswick

New Brunswick has the most diversified generating base in Atlantic Canada, with thermal generation accounting for about one half of the total in-province energy requirements, and hydro, nuclear and biomass accounting for the other half. The province has surplus generating capacity allowing it to serve adjacent markets in Canada and in the U.S. NB Power is the principal electricity supplier to Prince Edward Island and makes significant exports to New England. Exchanges also occur with Québec and Nova Scotia.

Under New Brunswick's new energy policy, introduction of competition in the wholesale and large industrial sectors is scheduled for 1 April 2003. The provincially-owned corporation, NB Power, will be restructured into a holding company with subsidiaries required to operate on a commercial basis. NB Power Transmission will function under the direction of the Independent System Operator, providing non-discriminatory transmission access to customers inside and outside the province.

3.8.1 Transmission Interconnections

New Brunswick has the most extended transmission network in Atlantic Canada with several interconnections allowing it to trade electricity with the U.S. Northeast. The major power line is a 345 kV line that interconnects at Orrington, Maine with export transfer capacity to New England of 700 MW while import capacity is 300 MW. Two smaller interconnections with a transfer capacity of 120 MW serve isolated loads within the state of Maine.

NB Power has been working with Bangor Hydro Electric to build a second 345 kV transmission line and interconnection with the New England market. The proposed project is planned for completion in 2005. The line would be used for import and export opportunities and provide improved transmission reliability and efficiency. The utility has been involved in the creation of a Northeastern RTO (e.g., ECTO). RTO development would complement NB Power's existing interconnection capacity with utilities in P.E.I., Nova Scotia and New England. It would also favour more trade and improve market efficiency.

NB Power has also pursued the development of the Neptune Project, a proposed merchant undersea HVDC electric transmission system. This proposed project would connect generation sources in Maine, New Brunswick and Nova Scotia, to generation-constrained markets in Boston, New York City, Long Island and Connecticut.

3.8.2 Exports and Imports[1]

Exports

The traditional export market for New Brunswick is New England (primarily the State of Maine), where competitive wholesale markets were established in March 1997. NB Power has not obtained an electric power marketer licence from the FERC; therefore, all export sales are terminated at the U.S. border and are subsequently handled by another export/trading entity. NB Power expects to qualify for a FERC licence when the wholesale markets and transmission open in April 2003.

Electricity exports from New Brunswick were depressed during the 1992-1994 period, due to a relatively high power surplus available from Québec. The introduction of competition in wholesale electric power markets in New England was a key factor contributing to increases in non-firm exports during 1997-1999. Total exports reached a record high of 5 TW.h in 1999 and have trended downward over the 2000-2002 period (Figure 3.8.1). The share of exports has varied between 20 and 30 percent of total provincial generation. Exports are generally dependent on New England market conditions and the availability and cost of NB Power resources.

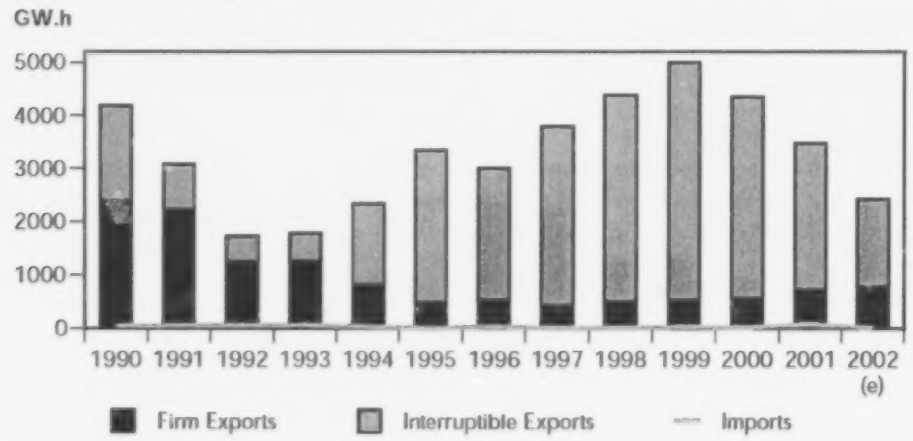
Historically, exports were for the most part associated with long-term firm contracts with New England utilities. As these contracts expired and were not renewed, firm exports declined sharply over the 1992-1994 period. Since 1995, firm exports have remained in the range of 0.4 to 0.7 TW.h annually while non-firm exports have varied between 1.5 and 4.5 TW.h. Over the last three years, non-firm exports accounted for 60 to 90 percent of the total.

Imports

Considering its generating capacity and access to supply from Québec and Nova Scotia, New Brunswick imports negligible amounts of electricity from the U.S. to meet its domestic requirements. As a result, over the last ten years annual imports have generally remained below 80 GW.h.

FIGURE 3.8.1

New Brunswick Exports and Imports



Source: NEB

1 Unless otherwise specified, exports and imports in this report refer to international electricity transfers between Canada and the U.S.

New Brunswick has been and continues to be the principal electricity exporter in Atlantic Canada. Net electricity exports have fluctuated in the range of 2.5 to 5.0 TW.h annually.

3.8.3 Export and Import Prices[1]

Export Prices

Prior to wholesale market opening in New England, firm export prices were generally higher than non-firm export prices by about $10 to $20 per MW.h. Over the last three years, the gap has become insignificant due to price volatility in the New England electric power markets. Since 1998, export prices have trended upward, rising from just above $40 per MW.h in 1998 to an all-time peak of about $75 per MW.h in 2001. Export prices declined in 2002 but remained volatile and significantly higher than historical levels (Figure 3.8.2).

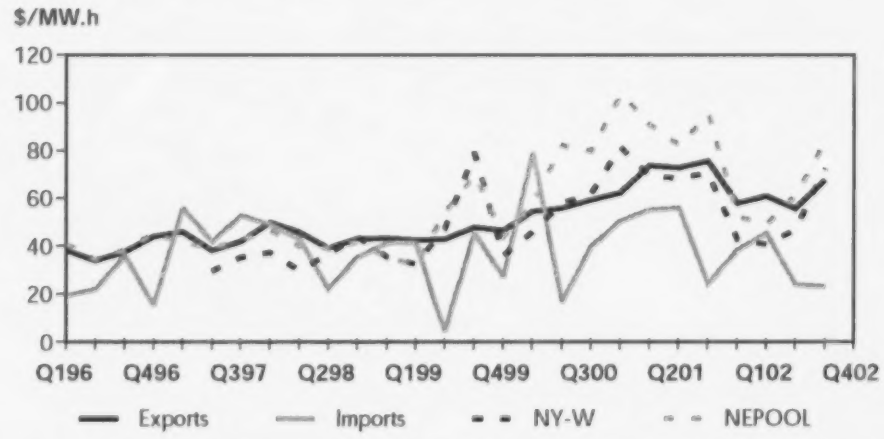
New Brunswick export prices tend to follow the patterns of New England prices. Since most exports occur during peak periods, the New England on-peak price is a key determinant of the New Brunswick export price. Occasionally, the export price may diverge from the New England price. For example, in spite of a sharp decline in the New England prices in 2000-2001, compared to 1999-2000, NB Power did not experience a significant year-over-year drop in its average export price. This was because it utilized a balance of spot price sales and sale contracts based on forward prices. Moreover, the correlation between New England prices and export prices may also be affected by NB Power's use of hedging instruments to manage the risk associated with price volatility in export markets.

Import Prices

Import prices, which are relatively more volatile than export prices, have mostly fluctuated in the range of $20 to $60 per MW.h. Import prices are typically lower than export prices, which would suggest most imports may have occurred during off-peak periods when prices are relatively low.

FIGURE 3.8.2

New Brunswick Export and Import Prices vs. U.S. Northeast Prices



Source: NEB, PIRA. New York West and NEPOOL prices are average on-peak prices (7:00 a.m. - 11:00 p.m., Monday to Friday).

1 The prices for exports (imports) in this report reflect the average amount paid per MW.h of electricity exported (imported), based on the quantities and corresponding dollar amounts reported to the NEB.

3.8.4 Implications for Domestic Consumer Prices

Electricity exports have been a major source of revenue for NB Power. Total export revenue nearly tripled over the period 1994-2000 from about $80 million in 1994 to $250 million in 2000 (Figure 3.8.3). Over the 1999-2001 period, export revenue varied between $220 million and $250 million, equivalent to about 15 to 20 percent of NB Power's total annual sales. Margins on exports have allowed the utility to keep rates for in-province customers lower than they otherwise would be. NB Power has estimated the rate reduction for domestic consumers, as the result of out-of-province sales (including interprovincial sales), to be between 10 and 15 percent. Exports generally contribute more toward domestic rate reduction than interprovincial sales, since they have higher quantities and higher margins.

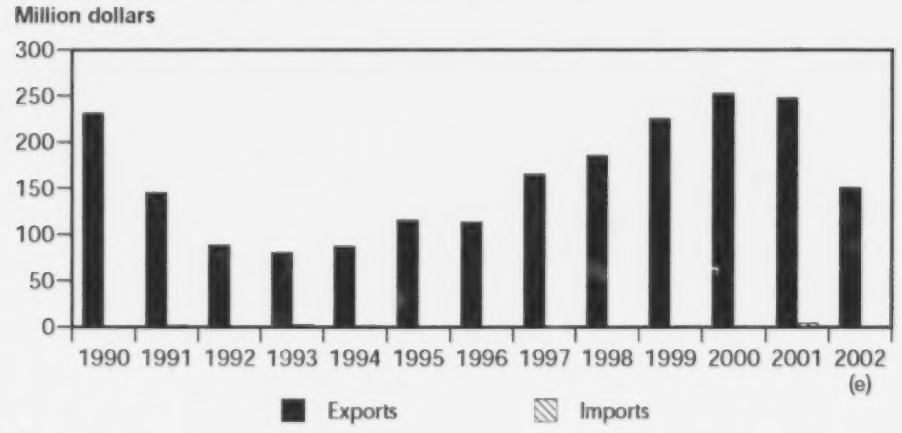
3.8.5 Factors Influencing Future Trade

Several factors might affect the future of New Brunswick electricity trade. With restructuring underway, NB Power expects to obtain a power marketer licence from FERC, which would facilitate its direct access to U.S. wholesale markets. If implemented, the proposed Neptune project, as well as the proposed 345 kV new line to New England, will add more transmission capacity from New Brunswick to the U.S. Northeast. NB Power will also benefit from an eventual reduction in pancaking of transmission rates which would result from the creation of a Northeastern RTO (e.g., ECTO).

The future electricity surplus will partly depend on whether the Point Lepreau nuclear station, which provides about a third of provincial load requirements, will be refurbished or not, and in the latter case, how much of that capacity would be replaced. The provincial Board of Commissioners of Public Utilities recently recommended not to refurbish the nuclear station essentially for economic reasons. A government decision on the Point Lepreau station is expected in early 2003. Another factor influencing trade is the ability of NB Power to remain competitive. In addition to the competition from low-cost hydro electricity from Québec, NB Power must also compete with recently-built, and proposed, efficient combined-cycle plants in New England.

FIGURE 3.8.3

New Brunswick Export Revenue and Import Costs



Source: NEB

3.9 Prince Edward Island

P.E.I. relies almost exclusively on firm contractual long-term transfers from New Brunswick (via two submarine cables with a total transfer capability of 200 MW) to meet its electricity load requirements. Due to rapid demand growth of two to three percent annually in recent years, Maritime Electric Company Limited (MECL), the principal electric utility on the island, has focused on developing additional generation locally, in particular, wind energy. If natural gas were made available, this could facilitate new generation on the island. MECL is also pursuing RTO discussions with NB Power, Nova Scotia and New England utilities, with the aim of gaining access to competitive supply sources. P.E.I.'s geographic location and its unique dependence on electric power from New Brunswick are key export and trade constraints. Although consumers in P.E.I. cannot benefit directly from export revenue, the prices they pay are tied to those in New Brunswick, which normally would be higher without export revenues.

3.10 Nova Scotia

Due to its geographic location, Nova Scotia does not have direct transmission access to the U.S. Northeast. It relies primarily on electricity produced locally and to a lesser extent, on transfers from New Brunswick to meet in-province load requirements. Although NB Power has had a form of open access transmission since 1 January 1998, Nova Scotia Power Inc. (NSPI), the largest utility in the province, has not concentrated on developing export markets as this has been considered by its parent company, Emera, as a non-core utility function.

Historically, the province was not involved in international electricity export/trading activities. With restructuring occurring in neighboring jurisdictions, some barriers to international trade are being alleviated or removed. The potential benefits associated with export and trading opportunities provide incentives for provincial stakeholders to assess the emerging opportunities.

In 2001 for the first time, NSPI reported 350 GW.h of firm exports to Maine. NSPI holds two export permits issued by the NEB, allowing it to export annually up to 1.2 TW.h of firm or interruptible energy. Transactions were facilitated by Emera Energy, an Emera subsidiary, which holds the necessary licences to trade in the U.S.

Future electricity exports from Nova Scotia will depend on two key factors, namely transmission access and generation. Currently, transmission access is limited since NB Power holds about 95 percent of the transfer capacity from New Brunswick to Maine. Subject to the NEB approval, a second interconnection line (345 kV) to Maine would be built. Moreover, open access to the New Brunswick grid is expected to be introduced on 1 April 2003. Improved transmission access and additional generation resources would allow higher electricity exports from Nova Scotia. NSPI has been involved in RTO discussions with other Atlantic and New England utilities.

3.11 Newfoundland and Labrador

Most generating capacity in the province is concentrated in Labrador, which has one of the largest hydro facilities in Canada at Churchill Falls. Practically all provincial electricity surpluses are destined to Québec through long-term contractual arrangements. Québec exports some of the Churchill Falls power directly for Newfoundland.

Annual transfers to Québec vary in the range of 30 to 35 TW.h, by far the largest interprovincial transfers in Canada. Transmission on the island is isolated while Labrador is interconnected to the

North American grid through Québec via three HVDC (735 kV) lines. Access to the Québec transmission grid is a key requirement if additional exports are to occur. The province is pursuing, in partnership with Québec, the development of the Gull Island project, which would increase generating capacity in Labrador by about 2 200 MW. This project may generate surplus electricity that can be exported but it is unlikely to be implemented before 2012.

OBSERVATIONS

This report has examined electricity exports and imports, and associated revenue and pricing trends, on a provincial basis and has identified a number of unique regional circumstances that have caused exports and imports to vary in response to changing market conditions. A number of observations on the analysis follow.

Electricity Exports and Imports

Exports have fluctuated significantly from year to year as the result of specific events, such as the lay-up of nuclear generation plants, high gas prices and the California electricity crisis in 2000-2001, as well as variable weather and hydraulic conditions. On balance, exports have declined over the past four to five years, reflecting increased domestic demand combined with no corresponding increase in generation capacity. With rising imports during that period, net exports have declined.

However, as the result of stronger electricity export prices, Canadian international electricity trade has continued to yield net revenues of $1 billion to $2 billion per year, except in 2000 and 2001, when they were about $3 billion.

The magnitude of trade and the factors motivating trade vary by province. For example, Manitoba, Québec and British Columbia are direct exporters from their reserve margins whereas Ontario, Saskatchewan and Alberta to some degree utilize trade to balance domestic resources. In general, electricity trade provides the opportunity to optimize the use of generating resources.

Provinces where hydro power is the dominant source of electricity generation, such as Québec, Manitoba and British Columbia, typically have the most opportunity to trade. Large hydro systems tend to result in spare generating capacity and surplus energy. While demand grows at a relatively steady rate, large hydro projects add capacity in blocks so after a hydro project is completed, the utility is likely to have surplus power. Additionally, for long-term system reliability and capacity design, companies often plan on the basis that hydro projects will provide only the amount of energy that could be generated under the most unfavourable hydraulic conditions. Since hydraulic conditions are generally better than allowed for in the planning assumptions, excess power becomes available. Finally, hydro projects allow for virtual storage of electricity, whereas electricity generated at thermal facilities cannot be stored. These relative characteristics of hydro and thermal generation provide utilities with opportunities to engage in energy banking. This typically involves a thermal generator selling off-peak power to a hydro generator allowing the latter to store water in its reservoirs. During periods of high demand, the hydro generator releases enough water to meet its own needs and to assist in meeting the peak demand of the thermal generator.

Provinces that rely on thermal generation do not typically have as much opportunity to trade. Electricity generating technology is not much different in Canada than it is in the U.S., and there is not much difference in the availability and price of fuels. Therefore gas-fired or coal-fired generators

in Canada and adjacent regions in the U.S. tend to have similar costs. If a Canadian generator wanted to sell thermally-generated power into the U.S., the added costs of transmission would usually result in the Canadian electricity being higher priced than the electricity generated locally in the U.S. From this perspective, there is not much inducement to trade, and provinces that mainly rely on thermal generation tend to trade only a little, or not at all, unless peak demand periods differ.

Utilities may benefit from trade in other ways. For example, some Canadian jurisdictions use electricity to heat homes, while adjacent U.S. jurisdictions use electricity to provide air conditioning. This results in demand being highest in the Canadian jurisdiction during the winter months, and highest in the U.S. jurisdiction during the summer months. Both utilities could build enough generation to meet their peak demand, but this would be expensive and would result in idle generating capacity for several months of the year. Instead, if sufficient transmission is available, utilities can make seasonal diversity exchange agreements in which the Canadian jurisdiction is supplemented in winter and the U.S. jurisdiction is supplemented in summer. This reduces the need for generating facilities and results in lower generation costs to both utilities.

Much of the power exported to the U.S. is generated from hydro power which does not cause greenhouse gas emissions and which is considered by some to be a "green" power source. Some U.S. jurisdictions have renewable portfolio standards, which specify that a certain percentage of a company's generation must come from renewable power sources. If electricity generated from large hydro projects were to qualify for inclusion in renewable portfolio standards, companies would have an added incentive to purchase Canadian hydro power.

Canada ratified the Kyoto Protocol in December 2002 and plans to implement policies to achieve the commitments made under the Protocol, that is, to reduce greenhouse gas emissions by six percent from the 1990 level of emissions by the period 2008-2012. Incremental hydro power would assist Canada in meeting these commitments if this power were to reduce or displace power generated from fossil fuels in the same province or other provinces. This, in turn, could require significant investment in transmission, for example, if new hydro projects in Manitoba or Québec were developed to displace coal-fired generation in Ontario.

Electricity exports as a percentage of total electricity production is much lower than that of oil and gas, where exports have been instrumental in furthering oil and gas resource development. Natural gas exports, for example, have constituted more than half of Canadian natural gas production in recent years (58 percent in 2001) whereas electricity exports have typically been 7-9 percent of production. As indicated above, generating capacity has been built primarily to meet domestic demand. With more open markets, it appears that an important aspect of electricity trade between Canada and the U.S. will be to optimize generation facilities on both sides of the border and improve reliability.

Although the NEB has seen some acceleration in interest for new export permits by marketers, recent exports trends do not lend support to the prospect of a substantial increase in overall exports in the immediate future. There is some potential upside to exports that could result from the return to service of nuclear units in Ontario, depending on the timing, and continued availability of Ontario's other supply options. Over the longer term, exports may increase due to: the possibility of large hydro developments; the projected surplus of electricity resulting from cogeneration projects in the Fort McMurray area; and improved transmission access to the U.S. Imports may also increase over time as a result of increased trading activities, especially from provinces with hydro storage capacity.

Electricity Export and Import Prices

As illustrated in Chapter 3, at the provincial level, export and import prices often reflect the pricing trends in the adjacent U.S. wholesale markets. This suggests that there is some degree of market integration at the wholesale level, i.e., power can flow based on market price signals and many provinces benefit from being able to export or import. In some cases, market integration is constrained by existing transfer limits and/or transmission congestion, and not all provinces have direct access to the export market (e.g., Alberta, Nova Scotia and Newfoundland and Labrador).

The relationship between export and import prices varies from province to province. When export prices are higher, particularly for the hydro provinces, it is because exports generally occur during peak periods when prices are relatively high, and imports occur during off-peak periods. When import prices are higher than export prices, it is normally because imports are needed at peak periods to compensate for local supply deficiencies.

Implications for Consumers

In recent years, electricity prices have been extremely volatile in some market areas, as evidenced by trends in import and export prices. Volatility can be exacerbated by fundamental supply/demand imbalances, for example, when growth in generation fails to match growth in demand.

Canadian consumers remain generally protected from price volatility through utility regulation. Moreover, some provinces, such as B.C., Manitoba and Québec, use export revenue to maintain domestic prices at levels that are lower than they would otherwise be. Since May 2002, Ontario has had a competitive wholesale market in the form of the IMO-administered market. Prices are determined by bids and offers submitted by market participants and reflect import and export opportunities. However, with the implementation of a retail price cap until 2006, a large portion of Ontario consumers will not be affected by the price changes in the wholesale market. Thus, with the exception of Alberta, there is no direct relationship between consumer prices and a competitive wholesale market. From this perspective, electricity prices are different from oil and gas prices that Canadian consumers pay, which reflect supply and demand conditions in competitive markets.

For those jurisdictions where the market structure is moving toward open markets and unbundling the traditional vertically-integrated structure, market price signals are required to promote the appropriate climate for investment in generation and transmission.

Transmission and RTOs

The structure of the North American transmission grid is being reshaped by the FERC RTO and Standard Market Design (SMD) initiatives. Many market participants believe RTO development will promote trade by increasing access and lowering transmission costs. Practically all provinces have expressed interest in some form of participation in RTOs. Manitoba has already concluded a coordination agreement with the MISO and B.C., New Brunswick and Nova Scotia have supported RTO membership. Québec, Ontario and Alberta are assessing their strategic options.

While many industry and regulatory participants feel that SMD is necessary for the RTO initiative to work, there are a number of operational and regional issues that need to be addressed. FERC has targeted 2004 for the implementation of SMD and has expressed its willingness to recognize specific regional circumstances. Apart from the technical challenges posed by the implementation of SMD, or

achieving operational compatibility with SMD, concerns in Canada have been raised with respect to regulatory sovereignty, RTO governance, and ensuring that the interests of Canadian consumers are not compromised.

Canadian entities have also identified the need for more transmission to the U.S. as a means to foster future trade and improve transmission reliability. South of the border, congestion has frequently occurred in specific market areas, such as in the vicinity of New York, Boston and southern California, which has exerted a constraining effect on Canadian export levels. Although Canadian international transmission lines do not generally appear to face congestion problems, there have been indications of capacity constraints and access issues, particularly for those provinces that do not have direct connections to U.S. markets. To improve access to U.S. markets, a number of new transmission projects have been proposed over the past two to three years. An innovative aspect of some of these proposals is that they would be merchant power lines (e.g., Lake Erie Link, Northern Lights and Neptune), targeting specific export markets.

GLOSSARY

Alternating Current (AC)	An electrical current that reverses direction at regularly recurring intervals with alternately positive and negative values, averaging zero. Almost all electric utilities generate AC electricity as its voltage is easily transformed to higher or lower values.
Average Cost Pricing	A pricing mechanism based on the average total system cost of providing a unit of electricity (per megawatt hours for wholesale, per kilowatt hours for retail) during a specified period.
Bilateral Contract	A private commercial arrangement between a customer and a supplier, which may or may not be a generator. The terms including price, amount, source, delivery point and time of energy consumption are all subject to negotiation. In practice, most bilateral contracts tend to be variations on a few standard patterns.
Biomass	Organic material such as wood, crop waste, municipal solid waste, hog fuel and pulping liquor, processed for energy production.
California/Oregon Border (COB)	The trading hub for bulk power (wholesale) sales at the California/Oregon Border.
Capacity	The maximum amount of power that a device can generate, utilize or transfer, usually expressed in megawatts.
Cogenerator	A generating facility that produces electricity and another form of useful thermal energy, such as heat or steam.
Combined-Cycle Generation	The production of electricity using combustion turbine and steam turbine generating units simultaneously.
Commercial Sector	Generally defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions.
Congestion	Congestion occurs when a transmission system cannot accommodate all transactions that would normally occur, for example, due to capacity constraints or reliability considerations.

Convergence	Maximizing the value of marketing, trading and arbitrage opportunities through optimization of energy conversion capacity. Convergence commonly involves electricity and natural gas.
Cost of Service	The process of regulation whereby the regulator sets rates at a level that will cover operating costs and provide an opportunity to earn a reasonable rate of return on the invested property devoted to the business. Also known as rate-of-return regulation.
Cross-Subsidization	The practice of charging higher prices to one group of consumers in order to provide lower prices for another group.
Demand-Side Management	Actions undertaken by a utility that result in a change and/or reduction in demand for electricity. This can eliminate or delay new capital investment for production or supply infrastructures and improve overall system efficiency.
Direct Current (DC)	Electric current that flows in one direction with little or no voltage fluctuation.
Distribution	The transfer of electricity from the transmission network to the consumer.
Diversity	The difference in peak demand on a daily or seasonal basis between regions. For example, peak demand generally occurs during the winter in Canada, while it occurs in the summer in some States. Diversity can be used as a basis for trade (see energy banking).
Economy Energy	Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.
Energy Banking	The storage of water in a reservoir during off-peak times to be released for generation during peak times.
Firm Power	Power or power-production capacity that is intended to be available at all specified times during a period covered by an agreement respecting the sale thereof.
Forward Market	An organized exchange where standardized contracts for the future delivery of electricity are traded according to established rules and regulations.
Generation	The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced.
Greenhouse Gases	Gases such as carbon dioxide, methane and nitrous oxide, which actively contribute to the atmospheric greenhouse effect, i.e., increased temperatures in the earth's lower atmosphere.

Green Power	Electricity generation deemed to be environmentally less intrusive than most traditional generation, usually in accordance with standards established by government or regulatory agencies. Green power sources include wind, water, landfill gas, solar, and others.
High Voltage Direct Current	This technology is used to solve the problem of transmitting electricity over long distances. Direct current power loss over long distances is considerably less than alternating current. A higher voltage is used with direct current to increase energy transmission and reduce losses.
Industrial Sector	Generally defined as manufacturing, construction, mining, agriculture, fishing and forestry establishments.
Interruptible Power	Power that is made available under an agreement that permits curtailment, interruption or cessation of delivery at the option of the supplier.
Independent System Operator (ISO)	An ISO is functionally separated from other electricity market participants, i.e., generators, transmission companies and marketers, and makes non-discriminatory access available to users of the transmission system.
Joule	A unit of work and energy. It is defined as the work done (energy transferred) in one second by a current of one ampere at a potential difference of one volt. One watt is equal to one joule per second.
Kilowatt hour	A measure of electric energy; the amount of electric energy required to operate ten 100-watt light bulbs for one hour.
Load Retention Rates	A rate that may be offered by an electricity supplier in order to retain existing customers. Normally the rate is only offered to large customers, which, if they were to switch to a lower-cost supplier or relocate to another power system, would "strand" significant generation assets on the host's power system. The rate is typically offered for a period adequate to provide the current supplier time to absorb the stranded generation onto its system, either through load-growth or contractual arrangements with other suppliers or customers.
Locational Marginal Cost Pricing	The variation in marginal pricing that may occur within a region due to the transmission distance. Ideally, the difference is the cost of transmission over a greater distance.
Marginal Cost	The cost associated with producing one additional unit of output, also known as incremental cost.
Market Power	The ability of a generator to establish a price on its own, without needing to compete with other suppliers.

Market-Clearing Price	The price at which there are no further gains to be made from further trading.
Merchant Transmission Line	A transmission line that would be physically independent from the regulated transmission grid and for which tolls and tariffs would be negotiated between shippers and the transmission line owner.
Mid-Columbia (Mid-C)	The trading hub for bulk (wholesale) power sales in east-central Washington state.
Mid-Continent Area Power Pool (MAPP)	MAPP is one of the administrative regions of the North American Electric Reliability Council (NERC). It includes Manitoba, Saskatchewan and all or parts of the states of Montana, Minnesota, North Dakota, South Dakota, Wisconsin, Iowa, Nebraska and Illinois.
Moral Suasion	In the absence of price signals, or enforceable rules, utilities encourage or discourage particular consumption behaviour by informing consumers of the benefits of the desired behaviour.
Natural Monopoly	An industry characterized by sufficiently large economies of scale that one firm can most efficiently produce the output to supply market demand.
Off-Peak	Hours of the day (e.g., from 11:00 p.m. to 7:00 a.m., Monday to Friday and all day Saturday and Sunday) or other periods (e.g., seasonal) with lower electrical demand.
On-Peak	Hours of the day (e.g., from 7:00 a.m. to 11:00 p.m., Monday to Friday) or other periods (e.g., seasonal) with higher electrical demand.
Open Access	Non-discriminatory access to electricity transmission lines.
Peak Load	The maximum load consumed or produced by a unit or group of units in a stated period of time.
PJM Interconnection L.L.C. (PJM)	PJM operates the transmission system and wholesale energy market in the tri-state area of Pennsylvania, New Jersey and Maryland.
Rate	The price charged for a commodity or service. Rates may be subject to regulatory approval or may be set by the marketplace.
Rate Pancaking (or Pancaked Rates)	Charging multiple rates over a transmission path. An example of rate pancaking is charging a rate based on total costs (fixed plus variable costs) over one or more intermediate transmission systems between the "source" (of generation) and "sink" (the eventual market), when the actual costs of moving that power (e.g., variable costs) are much lower.

Real Time Pricing	The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.
Regional Transmission Organization	A voluntary organization of transmission owners, transmission users, and other entities approved by the U.S. Federal Energy Regulatory Commission (FERC) to efficiently coordinate transmission planning (and expansion), operation, and use on a regional (and interregional) basis.
Renewable Portfolio Standard	A mandate requiring that renewable energy provide a certain percentage of total energy generation or consumption.
Reserve Margin	The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.
Residential Sector	Private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying.
Retail Access	A market in which electricity and other energy services are sold directly to consumers by competing suppliers. Also known as direct access.
Run-of-the-River Plant	A hydroelectric plant that depends chiefly on the flow of a river as it occurs for generation, as opposed to a storage project, which has space available to store water from one season to another. Some run-of-the-river projects have a limited storage capacity which permits them to regulate streamflow on a daily or weekly basis.
Simple Cycle	A combustion turbine that burns natural gas (or some other fuel) to drive a turbine, which in turn drives a generator to produce electricity.
Spot Market	Market where people buy and sell actual commodities or financial instruments for instant delivery. The spot market contrasts with the futures market, in which contracts are completed at a specified time in the future.
Stranded Benefits	Benefits that are released as a result of deregulation. For example, an increase in the price of electricity following deregulation represents an increased profit for utilities and is a stranded benefit.
Stranded Costs	Costs that cannot be recovered from market prices. With respect to electricity competition, stranded investments are those assets owned by a utility that would become uneconomic in a competitive market.

Tariff	The terms and conditions under which a service or product will be provided, including the rates or charges that users of a service or product must pay. Tariffs are usually proposed by the service or commodity provider, and are subject to regulatory approval.
Thermal Generation	Electric generation using a steam turbine or combustion turbine driven by biomass, fossil fuels or nuclear power.
Time-of-Use Rates	The prices are based on the time of day when the electricity is actually used. These rates allow consumers to pay less for the electricity they use during off-peak, or low electrical demand, periods. Electricity used during the on-peak hours is more costly.
Transmission	The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution.
Transmission Tariff	The authorized charge levied for provision and use of transmission services.
Unbundling	Separation of the vertically-integrated functions of utility companies into generation, transmission, distribution and energy services.
Utility	An entity owning and operating an electric system and having the obligation to provide electrical service to all end users upon their request.
Vertically-Integrated Utility	A utility that combines the functions of generation, transmission and distribution.
Wheeling	The transmission of power belonging to one utility through another utility's transmission grid.
Wholesale Access	A distributor of power has the option of buying its power from a variety of power producers on a wholesale basis for resale on a retail level.
Wholesale Transactions	Transactions between electricity generators and retailers.